

Long-Term Optimum Performance/Corrosion
Tests of Combustion Modifications for
Utility Boilers. Host Site: Louisville Gas and
Electric Company, Mill Creek No. 3

Exxon Research and Engineering Co.
Florham Park, NJ

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

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**LONG-TERM OPTIMUM PERFORMANCE/CORROSION TESTS OF
COMBUSTION MODIFICATIONS FOR UTILITY BOILERS**

**Host Site: Louisville Gas and Electric Company
Mill Creek No. 3**

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ABSTRACT

Corrosion in utility boilers, as possibly affected by combustion modifications (CM) for decreased NO_x emissions, was studied at large furnaces burning high sulfur coal. Under the first part of this program, each boiler was characterized to determine the short term effects of the various combustion modifications and controls on boiler operation, and emissions. Later, a Level 1 environmental assessment (EA) of boiler operation was performed, as well as tests to measure corrosion rate within the furnace, and two 30-day continuous emission monitoring tests. This report discusses the tests performed on Boiler No. 3 at Louisville Gas and Electric (LG&E) Company's Mill Creek Generating Station in Louisville, Kentucky. During the characterization tests, full load NO_x emissions (as equivalent NO_2) were decreased (by CM) by approximately 20% from about 235 ng/J (= 0.55 lb/MBtu = 400 ppm NO_x at 3% O_2 , dry) without adverse side effects. NO_x emissions during the 30-day tests were log-normally distributed with a mean of 202 to 220 ng/J and a geometric dispersion of 1.02 to 1.07. The Level 1 EA revealed no unusual environmental hazards resulting from low- NO_x operation, and resulting water wall corrosion rates were about 2 mils per year.

This report was submitted in partial fulfillment of Contract No. 68-02-2696 by Exxon Research and Engineering Company under the sponsorship of the U.S. Environmental Protection Agency. This report covers a period from March 1979 to March 1982.

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SUMMARY

For coal-fired utility boilers, NO_x emission regulations can often be met by using combustion modification techniques such as decreased total excess air flow. However, this can lead to a chemically reducing atmosphere within the furnace and an increased potential for corrosion. Under this program, methods of decreasing NO_x emissions were studied (characterization testing) from an environmental point of view as well as from a corrosion point of view. To this end, the program included three parts: Boiler Characterization, Level 1 Environmental Assessment (EA), and Corrosion Testing. Several large utility boilers were studied during this long-term performance/corrosion study. This report deals with the Number 3 boiler at Louisville Gas and Electric Company's Mill Creek Generating Station.

BOILER CHARACTERIZATION

Under the first phase of a long term performance/corrosion study (involving several large utility boilers), Exxon Research and Engineering Company (ER&E) identified and evaluated combustion modifications (CM) for decreased NO_x emissions. This report describes test work conducted at Louisville Gas and Electric Company's (LG&E) Mill Creek Generating Station, Boiler No. 3. The following combustion modifications were among those selected for detailed study:

- o Decreased total excess air flow
- o Biased firing (bottom burners fuel-rich)
- o Flue-gas recirculation

The operator's freedom to vary certain control parameters (such as excess air) was tightly constrained by programmed limits in the boiler's control system. Even so, the limited changes that could be made resulted in a 10-20% decrease in NO_x emissions (as NO_2) from the "as-found" case of about 235 ng/J (= 0.55 lb/MBtu = 400 ppm at 3% O_2 , dry) without adverse short term side effects. (The applicable NSPS maximum allowable emission rate is 301 ng/J (0.7 pounds/MBtu).) It is felt that by increasing the range of control on the excess oxygen, and with proper instrumentation (e.g., a CO monitor) it would be possible to decrease NO_x emissions even more.

During the initial short-term studies, furnace gas sampled from along the furnace walls confirmed that the region where corrosion was most likely to occur (low O_2 , high CO) was in the chemically reducing environment around the burner zone. Longer term effects (including corrosion) were studied in detail as the program continued.

LEVEL 1 TESTING

A Level 1 environmental assessment (EA) test was performed at Mill Creek No. 3 and involved the major inlet and effluent streams crossing the plant's process boundaries.

The analysis was performed to identify potential pollutants in the various streams and included three types of analysis. First, chemical analysis was used to determine the chemical composition of the various streams. Second, physical analysis on particles entrained in various streams provided information on shape, and size. Finally, biological analysis was used to gather information on the toxic, and/or mutagenic effects of the various streams.

As expected, most of the flue gases leaving the combustor and going to clean-up devices are fixed gases (O_2 , CO_2 , N_2 , etc.). Other components of this stream include sulfur compounds, hydrocarbons, and entrained particulate matter.

The particulate matter (fly ash entering the precipitator) represents most of the total ash leaving the furnace (the rest is slag or bottom ash and exits the furnace by another stream). More than 98% of the fly ash, (mostly the larger particles) is removed by cleanup devices before the flue stream is discharged through the stack.

The particulate matter and entraining flue gases contained low levels of organics including dimethyl sulfate (DMS). However the DMS may have been an artifact of the analytical procedure and not actually present in the flue gas stream.

The fly ash particles sampled from the precipitator hopper were less spherical than the SASS sample at the precipitator inlet, and had a bimodal size distribution with peaks at about 3-4 μm and at 20 μm . The composition was mostly silicates.

The effluent sluice water samples contained chloride and sulfate as did the coal and ash extracts.

The coal extract was separated into 7 fractions, but the spectra of each fraction were generally too complex to be analyzed by EPA IERL-RTP Level 1 procedures. Instead, the major peaks are listed in the report, and show that the extract was highly aromatic, highly oxygenated material containing phenolic material and carboxylic acids.

Biological tests (using living matter) were used to assess the environmental effect of process effluents on life forms. The results show that the coal, electrostatic precipitator (ESP) ash, and sluice water are not mutagenic. The Rat Alveolar Macrophage (RAM) Assays were also negative. The Chinese Hamster Ovary (CHO) Cell Assay yielded toxic responses with coal leachates and with sluice water. While moderate to high toxicity was also recorded for some of the aquatic assays, the sluice water caused no toxicity to any of the aquatic species studied, but was stimulatory to the growth of algae.

CORROSION TESTS

In order to more fully evaluate the longer term side effects of low- NO_x operation, corrosion testing began at the conclusion of the characterization period. Corrosion rate was measured by three methods:

- o Corrosion probes
- o Corrosion panels
- o Wall thickness mapping

The corrosion probe tests were of relatively short duration (30 to 1,000 hours). As expected, the new metal on the probes corroded at an initially high rate until surface conditioning occurred. Then, the rate of metal loss seemed to slow down (from more than 30 mils/yr to less than 10 mils/yr) as the exposure time increased, thus, approaching the expected (and actually measured) loss rate for the furnace walls. The corrosion panels had an average loss rate of 1.3 mils per year which compares well with the average wall loss rate of 2.3 mils per year.

No correlation was found (in any of the methods) between corrosion rate and location in the furnace. Furthermore, no difference in corrosion rate was seen among the steel types tested. On the average, the rate of corrosion within this boiler was such that it would require more than 30 years for the tubes to lose half their thickness. Therefore, corrosion rates, while operating in compliance with NSPS NO_x regulations, appear to be acceptable.

THIRTY-DAY CEM TESTS

Twice during the program, flue gas emissions were monitored for thirty-day periods using continuous emissions monitors (CEM) to help researchers understand the abilities, problems and performance limitations that might be associated with CEMs in similar situations. The data also proved useful for evaluating boiler emissions over normal load cycles for longer periods than during the earlier (characterization) tests.

During each 30-day test, NO (rather than total NO_x) was measured and the mass emission rate (ng/J or lbs/MBtu) of NO was reported as equivalent NO_2 . For the first test, the log-normal probability curve of the 24-hour averages has a mean NO value of 202 ng/J (as NO_2) with a geometric dispersion of 1.02. Similarly, for the second CEM test, the log-normal probability curve had a mean NO value of 220 ng/J (as NO_2) and a geometric dispersion of 1.07.

Although the boiler steam load varied widely (for example, from approximately 23 percent to 94 percent of maximum capacity during the first CEM test) the NO emission rate was fairly steady with the standard deviation being less than about 10 percent of the mean value. For both tests, NO emissions seem to be log-normally distributed with 99 percent of the values less than 250 ng/J (0.58 lb/MBtu) as NO_2 . This is less than both the original (1971), and new (1979) NSPS limits (300 ng/J [0.7 lb/MBtu] and 260 ng/J [0.6 lb/MBtu] NO_x as NO_2 , respectively).

The continuous monitor system (utilizing an extractive sampling system) provided accurate gaseous emissions data for the test duration. However, calibration of the instruments on a daily basis is necessary, as is maintenance of the sampling system.

PART A

PROGRAM INTRODUCTION AND GENERAL
DESCRIPTION OF THE TEST UNIT

I. INTRODUCTION

Under the sponsorship of the United States Environmental Protection Agency (EPA), (EPA Contract No. 68-02-1415) Exxon Research and Engineering Company (ER&E) has studied the effects of boiler operating conditions on oxides of nitrogen (NO_x) emissions. These and other studies led to improved operating procedures for NO_x control. The new procedures (known as combustion modifications (CM) for low NO_x) included decreased excess air flow, staged combustion, and other modifications which could increase the chemically reducing nature of the gases in certain regions of the furnace. The result could be an increased corrosion rate on the fireside of the boiler's water-wall tubes, especially in boilers fueled by high-sulfur coal.

As a part of this program, (EPA Contract No. 68-02-2696) furnace wall corrosion was studied at several coal-fired utility boilers, designed to use CM for decreased NO_x emissions. The modifications included decreased excess air flow, and use of special low- NO_x burners in order to meet the applicable new source performance standards (NSPS) for NO_x emissions (301 ng/J, or 0.7 pounds/MBtu, as NO_2).

II. PROGRAM STRATEGY

The test program contained several phases including:

- o Boiler Characterization
- o Corrosion Testing by
 - Probes
 - Panels
 - Wall measurements
- o Level 1 environmental assessment
- o 30 day continuous NO_x monitoring

In the Boiler Characterization phase of the work, effects of various boiler combustion modifications and controls were assessed and their ability to control NO_x emissions without causing short-term adverse side effects (such as increased slagging) were evaluated.

During this time, flue gas emissions and fuel and ash composition were monitored periodically. Also, furnace gas composition was monitored at various locations along the furnace wall in order to identify locally corrosive environments for further study.

Corrosion testing was initiated after the boiler characterization phase of this work. Three methods (corrosion probes, corrosion panels, and wall thickness mapping) were used to evaluate corrosion.

Corrosion probes were used to evaluate short term (30 to 1000 hours) corrosion effects. In this method, pieces of wall tube type materials (called corrosion coupons or test rings) were inserted into the furnace for various times and then weighed to determine the rate of metal loss. This qualitative, non-destructive method did not give a true reading of actual wall loss, but was an economically attractive alternative to other methods in which wall losses were measured more directly.

The corrosion panel method was probably the most reliable method used. In this method, sections of the boiler wall were removed, and replaced by new sections called corrosion panels on which the tube wall thickness had been carefully measured. About two years later, the furnace was re-entered (during an outage) and the panels were re-measured. The wall thickness measurements were made ultrasonically, a nondestructive test in which sound waves are bounced off the inner wall of the tube and the echo delay is measured.

The wall thickness mapping method involved ultrasonic thickness (UT) measurements of all walls throughout the furnace. The first set of such wall measurements occurred during the outage in which the corrosion panels were installed, and the second set was about two years later (coincidental with the final panel measurements).

During these long term corrosion tests, an EPA Level 1 environmental assessment (EA) test was performed and included physical, chemical, and biological analysis of all major streams entering or leaving the boiler. The Source Assessment Sampling System (SASS Train) was used to sample the flue gas stream while EPA Method 5 was used to measure particulate removal efficiencies. Other streams sampled included water, coal, and precipitator hopper ash.

Twice, during the two year corrosion exposure period, NO_x and other flue gases were monitored continuously for 30 days using a continuous emission monitoring (CEM) system. The 30-day CEM tests provided a better quantification of flue gas emissions over normal boiler load cycles and for a longer period than was possible during the characterization tests. These tests also gave the researchers an indication of how a CEM may be expected to perform (reliability, accuracy, maintenance needs, etc.) in other similar situations.

III. BOILER DESCRIPTION

Mill Creek No. 3 is the third boiler constructed at Louisville Gas and Electric (LG&E) Company's Mill Creek Generating Station in Louisville, Kentucky. Designed by Babcock and Wilcox Company (B&W), it burns about

200 tons of high-sulfur (3-4% S) coal per hour for production of 400 MW of electric power. It was designed to use combustion modifications (CM) (such as flue-gas recirculation and dual register low- NO_x burners) to meet the New Source Performance Standards (NSPS) for NO_x emissions (0.7 pounds/MBtu or 301 ng/J NO_x , as NO_2), and is one of the first boilers to be governed by this NSPS regulation.

The boiler's forty burners are arranged with twenty on the front wall, and twenty on the rear wall, in four elevations (rows) of 5 burners each (per wall). Four feeders and four mills designated A, B, C, and D supply pulverized coal to the forty burners. (The coal is blown into the boiler by the primary air which makes up about 20% of the total air supply.) Because each feeder and mill feeds a group of 10 burners, each such group is turned on or off, and throttled as one unit.

The "A" feeder and mill control the fuel to the top ten burners (two rows of 5) on the rear wall. "B" is for the top two rows (10 burners) on the front wall. "C" and "D" are for the bottom two rows on the front and rear walls, respectively. Because of this fuel distribution system, it was not possible to shut down just one row of burners on a wall (as would be desired for over-fire-air simulation).

Each mill and feeder is supplied by a silo (four silos in all) which receives coal by conveyor belt from the storage pile. The silos (filling at the top and discharging through the bottom) hold about 6-8 hours (at full load) of fuel. Forced draft (FD) fans blow preheated air into this balanced draft furnace. After the air passes through the FD fan, a small portion (called primary air) is diverted through each mill and is used to blow the coal dust into the boiler. The remainder of the air is split among the four windbox compartments (one for each mill-group of 10 burners). From the windbox, air passes through the inner and outer registers of each burner and enters the furnace where it mixes with the coal to sustain combustion. The distribution of the air between the inner and outer registers is manually controlled by dampers. The damper control levers are located outside each burner. In this way, two concentric horizontal cylindrical sheaths of flowing air surround each coal stream discharged into the furnace by each burner.

After combustion, the hot gases pass through heat exchangers to produce about 3,000,000 pounds per hour of superheated steam at 2,500 psi and 1,000°F which is used to drive a turbine and generator to produce 400 MW of electric power for LG&E's customers. A portion of the gaseous combustion products (flue gas) can be recirculated through the boiler via the hopper for temperature and slag control, or via the windbox for NO_x control. (However, because the windbox recirculation feature had not been needed or used in some time, it was frozen shut, preventing flue gas from being recirculated through the windbox during these tests.) After leaving the boiler, the flue gas passes through a series of hoppers and a precipitator for fly ash removal, and then through a scrubber for SO_x clean-up before going up the stack. The ash that is

not fine enough to be carried away by the flue gas deposits on the boiler's water wall tubes and/or falls into the quench tank at the bottom of the boiler from which it is flushed to a settling pond.

IV. NOMENCLATURE

The back of the unit is defined as the side that the stack is on. The other walls (left, right, and front) are named by an observer facing the boiler with the stack on the far side of the boiler. Burner and mill/feeder designations (A, B, C, and D) have already been discussed with "A" at the top rear, "B" at top front, and "C" and "D" at the bottom front and bottom rear, respectively. The left side is also the north side (control room side of Unit 3) and for devices with number or letter designations (such as ducts), the numbers and letters generally run from north to south. For the purpose of this paper, the tubes making up the furnace walls are numbered from left to right on each wall as seen by an observer standing inside the boiler.

PART B
BOILER CHARACTERIZATION TESTS

I. PURPOSE OF CHARACTERIZATION TESTS

The purpose of the "Boiler Characterization" phase of this work was to assess the ability of the boiler's operating controls to effect combustion modifications for NO_x emission control without causing adverse side effects such as excessive CO emissions or increased slagging and corrosion. This was done just prior to initiation of corrosion testing on each boiler.

II. EXPERIMENTAL PROCEDURES

A. NO_x Controls Investigated

Boiler characterization at Mill Creek No. 3 involved the investigation and evaluation of several boiler operating parameters. The choice of controls selected for this study was based, in part, on boiler manufacturer's experience with NO_x control, and the desire to gain additional knowledge that would help to "fine-tune" this relatively new boiler.

The boiler combustion parameters selected for study included:

- o Amount of Excess Air
- o Fuel/Air Bias and Distribution Among the Boiler's 40 Burners
- o Burner Vane Settings (Flame Shape)
- o Flue Gas Recirculation (FGR) to Hopper

The effects of other combustion modifications on NO_x emissions were also noted during the tests, but they were not studied in detail since the operator's ability to manipulate and control them was tightly constrained by the boiler design and load demand, and thus were not really suitable methods of NO_x control. These included:

- o Firing pattern (mills out of service)
- o Load

B. Other Boiler Operating Data

1. Control Room Readings

During each test, all important available information concerning the boiler's mode of operation was recorded. Most of these data were available on the display board in the control room through a data logging computer and as such are called "control room"

(CR) or "board" readings in this report. The large volume of data collected makes it impractical to present all of it in this report. Instead, as an example, the control room data sheets from tests 46-48 are presented in Appendix A.

2. Coal Analysis

Coal samples were gathered periodically for analysis. (This was in addition to the daily analysis done by LG&E.) The purpose of the analysis was to determine what factors in the coal (heating value, sulfur, nitrogen) might be contributing to the performance of the boiler (e.g., flue gas flow rate, NO_x and SO₂ emissions). Coal analysis results may be found in Appendix B.

C. Effects Monitored

During the characterization period, ER&E measured the short term (from a few minutes to a few days) effects of modifications in the combustion control parameters mentioned in the previous section. The goal was to optimize the boiler's NO_x emissions through combustion modifications (CM) without creating problems in boiler operation or control. Effects measured included:

- o Flue gas composition (at economizer outlet)
 - O₂
 - NO_x (NO and NO₂)
 - CO
 - CO₂
 - SO_x (SO₂ and SO₃)
- o Stack plume opacity (by LG&E's own in-stack transmissometer, and by an EPA certified observer)
- o Furnace gas composition (for corrosive local environments)
 - O₂
 - CO
- o Slag within the furnace (by observation through inspection doors)
- o Flame shape and stability (by B&W observation through inspection doors)
- o Boiler flexibility of control

Figure B-II-1 is a simplified sketch of Mill Creek No. 3 and is referred to in the following discussion of sampling and testing.

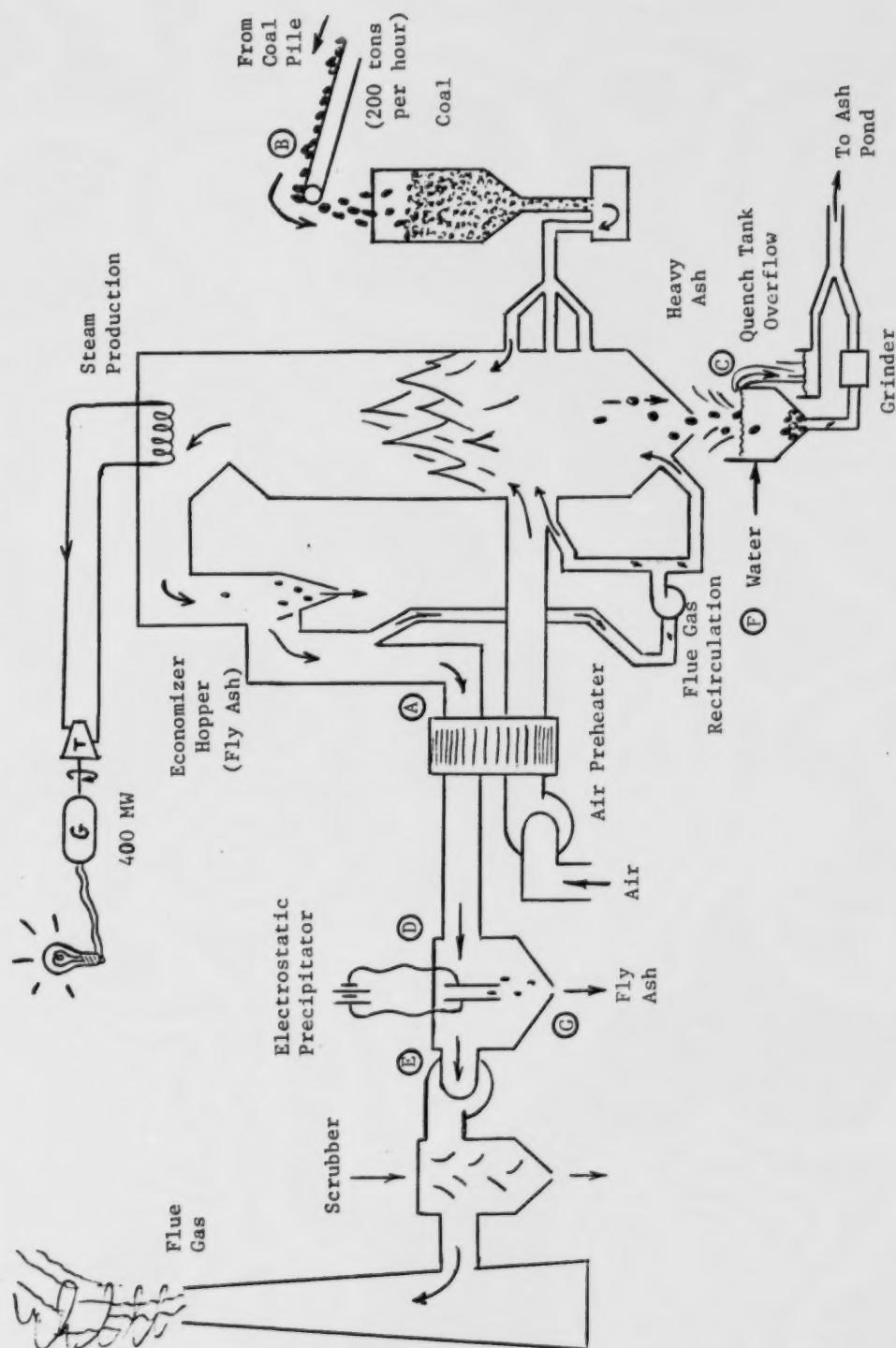


FIGURE B-II-1
 Mill Creek No. 3
 Process Flow and Sampling Locations
 (See Table C-II-1)

1. Flue Gas

Figure B-II-2 shows the gas sampling and analysis system. Flue gas was sampled downstream of the boiler's economizer section and upstream of the air heater. Hence, the sample represented combustion products rather than leaks from downstream components. (The sampling location is marked "A" on Figure B-II-1.) At this location, the temperature of the gas being sampled was about 600°F. Sampling tubes were assembled in four bundles of three and inserted vertically through ports on the top of the dual exhaust duct (two bundles in each of the two ducts). Each bundle of three sampling tubes (called a "probe") consisted of a short, medium, and long tube of 3/8" stainless steel.

The twelve sampling points were located as close as possible to the centers of twelve equal and mutually exclusive co-planar areas of the ducts' cross section. The gas was analyzed as a composite sample, three points (i.e., one probe) at a time. This method, though not in strict accord with EPA's method 1, has been shown to yield a representative sample.*

For each probe, the three samples flowed through heated teflon lines into a heated gas mixing and conditioning box. In the box, particulate matter was filtered from each sample, while still hot and free of condensed moisture. The three flow rates were then equalized and combined. As the sample exited the heated box, it flowed through a permeation tube dryer where water was selectively removed. The old style boxes (Figure B-II-2-B), incorporating flat disk filters were used through Test 36. However the filters plugged easily. Therefore, starting after Test 36, the new style boxes (Figure B-II-2-C) incorporating cylindrical by-pass filters and air eductors were put in service. Both systems used permeation tube dryers to remove water. For Test No. 49, because of consistent plugging, a jar packed with quartz wool was substituted for each box (one for each box).

Typically, the raw sample contained about 8% water vapor mixed with particulate matter. The heated, gas-conditioning boxes first removed the particulate matter, and then the water, thus preventing the formation of "mud" in the sampling lines. Removal of water allowed the sample to be subsequently cooled without fear of condensation which may have absorbed water soluble sample components such as NO_x , or in cold weather may have frozen and plugged the lines. With the water removed, the sample was allowed to cool to ambient temperature as it traveled under

*A. R. Crawford, M. W. Gregory, E. H. Manny, "Magnitude of SO_2 , NO , CO_2 , O_2 , Stratification in Power Plant Ducts," Exxon Research and Engineering Company, EPA Report No. EPA - 600/2-75-053, September, 1975. Prepared under EPA Contract No. 68-02-1722.

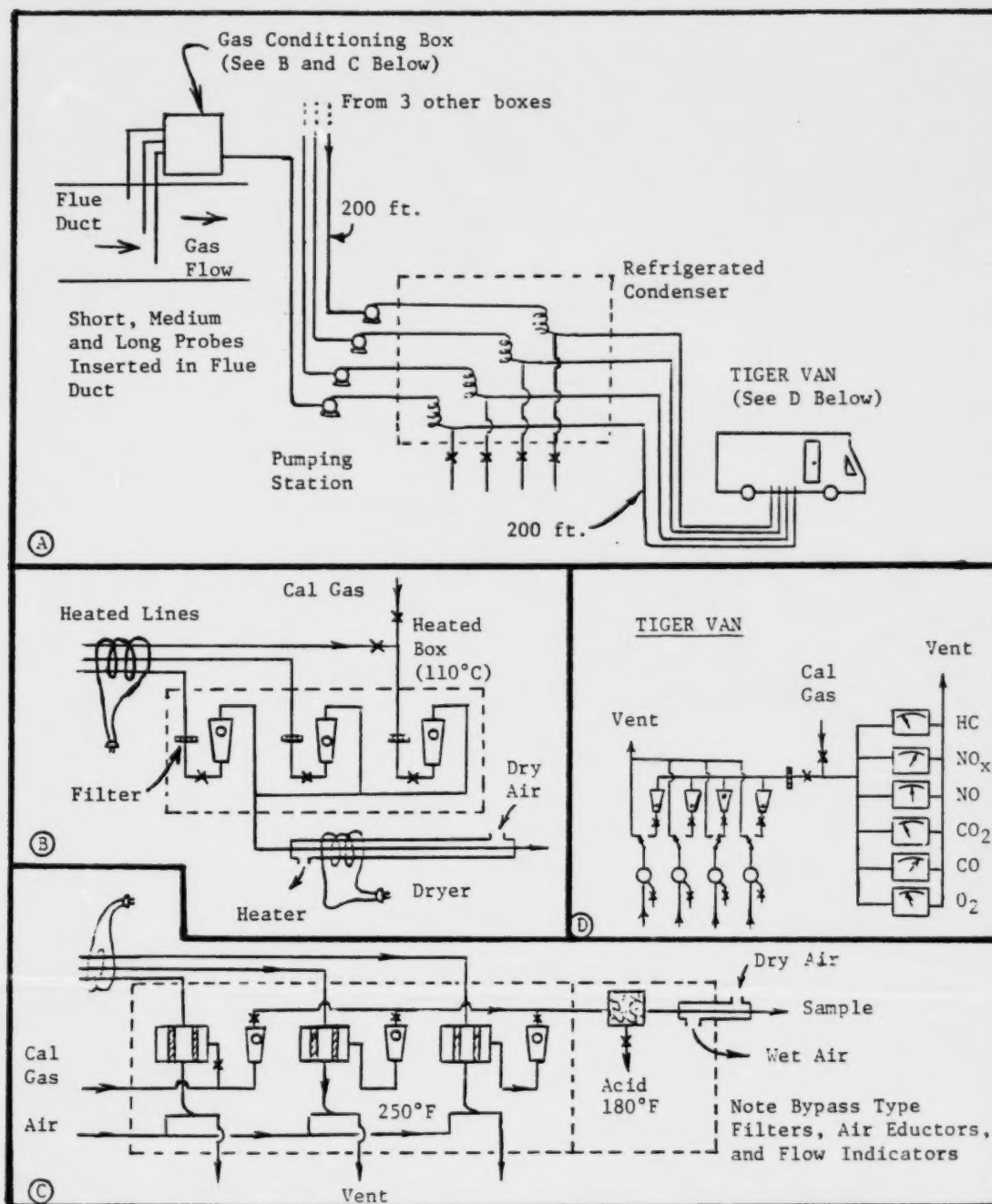


Figure B-II-2 Flue Gas Sampling and Analysis System

- A - General Layout
- B - Detail of Early Gas Conditioning Box
- C - Detail of Newer Gas Conditioning Box
- D - Detail of Mobile Analytical Van

vacuum about 200 feet through translucent inert plastic ("Polyflo" brand) tubing to the pumping station.

The sample entered the pump under 15 in. Hg vacuum where it was pressurized to 10 psig, and immediately entered a refrigerated coil cooling it to 35°F.* The refrigerator removed the last traces of water since pressurization of the sample by the pumps (downstream of the refrigerator) would promote condensation which might not have occurred on the vacuum side of the pump (upstream of the refrigerator). The dry sample (dew point <35°F) left the refrigerated condensation chamber still under pressure for its 200 foot journey through inert flexible lines to the instruments in the analytical van. Some of the analyzers are described in Table B-II-1.

As the gases entered the instrument van they passed through a final water trap before entering the sample selection system. There, the instrument operator selected one of the four composite samples to be distributed to the continuous gas analyzers. The other three were vented thus keeping each sample line filled and continuously purged with its own flowing sample all the way to the sample selector valves in the van. This minimized response time when switching sample lines.

Generally, only one sample (representing an equal composite of three sampling points), was monitored at a time. After about two minutes, the next composite sample was monitored, and so forth. For special tests, through use of the system's valves and flowmeters, a composite (in any ratio) of any one or more sample points could be mixed and fed to the instrument train. This was useful for leak checks, diagnostics, weighted averaging, calibration checks, and certain tests which required close monitoring of a critical sampling point or set of points. The sample required approximately two minutes to travel through the nearly 400 feet of 3/8 inch tubing from the sampling point to the instrument train.

(Other systems were used for SO₂-SO₃ analysis. These are discussed elsewhere in this report.)

Calibration was done by introducing "cal gas" at each gas analysis instrument, as well as at several probes. Leak checking was done by monitoring the sample's oxygen concentration (a leak on the vacuum side of the pump would draw in air, causing the O₂ analyzer to show an unusually high reading), or by introducing "cal gas" at the probe and monitoring its dilution. It was found that as long as the oxygen analyzer indicated no critical leaks,

*During some tests, mechanical problems prevented the use of the refrigerated condenser. The condenser was generally not used after test no. 36.

TABLE B-II-1

MOBILE ANALYTICAL LABORATORY
CONTINUOUS GAS MONITORS AND
CALIBRATION STANDARDS

Gas Monitored	Method	Manufacturer & Model	Measuring Ranges	Calibration Standard*
NO	non-dispersive infrared (NDIR)	Beckman	0-400 ppm 0-2000 ppm	3
NO ₂	non-dispersive ultraviolet (NDUV)	Beckman	0-100 ppm 0-400 ppm	4
NO/NO _x	chemiluminescent	Thermo Electron 10 A	0-25 ppm 0-10 ppm 0-25 ppm 0-100 ppm 0-250 ppm 0-1000 ppm 0-2500 ppm 0-10000 ppm	3 & 4
O ₂	polarographic	Beckman	0-5% 0-25%	2 & 5 6
CO ₂	non-dispersive infrared (NDIR)	Beckman	0-20%	2
CO	non-dispersive infrared (NDIR)	Beckman	0-200 ppm 0-1000 ppm 0-25000 ppm	2 1

*See Table B-II-2 for composition of calibration gas mixtures. In all cases nitrogen (mixture No. 8 on Table B-II-2) was used for the "zero" check.

TABLE B-II-2

COMPOSITION OF STANDARD GAS MIXTURES USED
FOR CALIBRATION OF GAS ANALYZERS
(THIS TABLE FOR USE WITH TABLE B-II-1)

COMPOSITION

MIXTURE NUMBER	COMPONENTS	CONCENTRATIONS*
1	CO	15,000 PPM
2	CO CO ₂ CH ₄ H ₂ O ₂ H ₂ O	150 PPM 13% 25 PPM 1% 4-5% Dry
3	NO	450 PPM
4	NO NO ₂	450 PPM 45 PPM
5	O ₂	4%
6	Air	100%
7	SO ₂	500 PPM
8	N ₂	100%

In addition to the above, National Bureau of Standards (NBS) gases were kept and used as reference checks when accepting new calibration gases from suppliers. Each cylinder of calibration gas could be checked against its NBS counterpart.

*Nitrogen makes up the balance of all mixes.

it did not matter, except for CO, whether calibration was done at the probe or at the gas analyzer. In the case of CO, it was discovered that the reading drifted upward very rapidly unless the instrument was cleaned frequently. Hence, some of the early CO readings (prior to test no. 27) may be falsely high. The composition and use of the calibration gases is summarized on Table B-II-2.

When evaluating operating parameters, such as combustion modifications during boiler characterization tests, the testing team would first wait for the boiler to reach steady state. Then at two minute intervals, the flows in each of the four sample lines would be fed, in turn, to the gaseous analyzers and the results would be recorded on a form suitable for computer processing. The cycle was repeated until each of the four sample streams had been analyzed three to five times.

The next step was to have the boiler operator adjust the boiler's combustion parameters (such as amount of excess air) for another test, wait approximately 1/2 hour for steady state, and analyze the flue gas as before. Each such test required about an hour.

At the conclusion of the testing visit, the data would be computer processed and reported in terms of a standard dilution - usually 3% oxygen.

Many tests involved adjustment of excess oxygen flow and subsequent observation of its effect on NO_x emissions. During set-up for these tests, air flow was slowly decreased until CO emissions began to rise. A remote indicator installed in the control room duplicated the O₂, CO, and NO_x readings displayed in the analytical van. During test set-up, the instrument operator in the van switched the sample selector to monitor a location in the flue gas exhaust duct where the O₂ and CO concentrations were most critically low or high, respectively. Hence, as the boiler operator decreased the air flow rate, he was able to see almost immediately, on the remote indicator, how this was affecting CO and NO_x emissions. Observers in both the control room and the analytical van kept in constant radio contact during boiler set up. Visible stack emissions were frequently monitored by a certified smoke observer.

Each test began after a short (5-10 minutes) observation period to be sure that the boiler was operating in steady state. Once in steady state, the control room observer recorded all critical boiler operating parameters so that emissions could be correlated with operating mode.

Until recently, emission monitoring equipment had not been a standard part of most boilers' instrumentation. Consequently,

boilers may have been operated at higher air feed rates than necessary for complete combustion. Even now, most boilers are not equipped with a CO monitor to aid in decreasing air flow. The excess air may exit the stack as wasted heat, lost efficiency, and NO_x.^{*} The equipment used in these tests helped to control these effects.

2. SO₂ and SO₃ Analysis

A modified version of EPA Methods 6 and 8 was used to analyze flue gas for SO₂ and SO₃ during test no. 48. A sketch of the system is shown in Figure B-II-3.

Flue gas was withdrawn under vacuum from the flue duct and bubbled through a series of impinger bottles containing solutions designed to absorb SO₂ and SO₃, respectively.

The first impinger contained isopropyl alcohol (IPA) to absorb SO₃. It was followed by peroxide (H₂O₂) solutions for absorbing SO₂. The amounts absorbed were determined by titration. For SO₃ determination, barium perchlorate (BaCl₄) was the titrant, and thorin was the colorimetric indicator. For SO₂, the titrant and indicator solutions were sodium hydroxide (NaOH) and methyl-orange, respectively.

3. Plume Opacity

Plume opacity was measured by an EPA-certified, smoke reader.** In addition to the observer, the data from the in-stack transmissometer were also recorded on the control-room board-data sheets.

4. Gaseous Samples at Furnace Wall

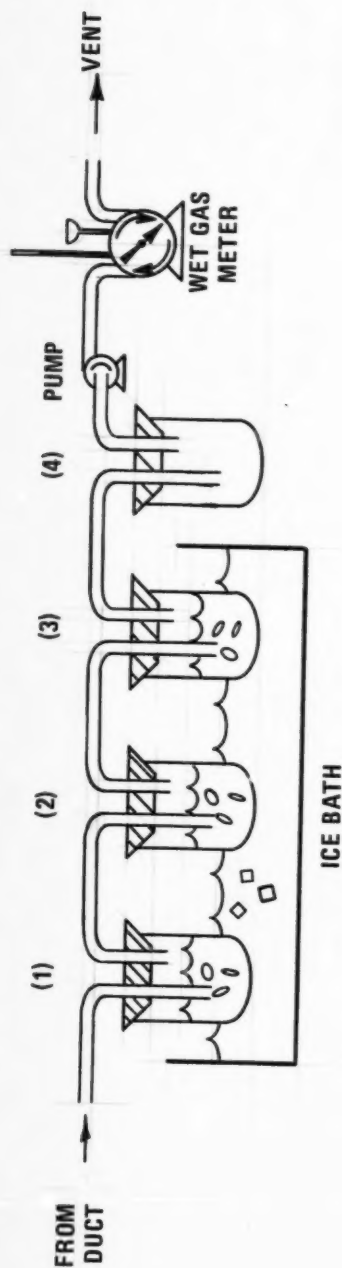
In addition to flue gas sampling, another type of gaseous sampling (called furnace gas-tap testing, test no. 47), involved the extraction of gases directly from various places along the walls of the combustion zone so that local potentially corrosive environments could be identified and selected for further study.

In preparation for the furnace gas tap study, approximately forty 1/4 inch holes were drilled through the furnace wall (in the

^{*}See also: When it Pays to Monitor CO "Power" magazine, (McGraw Hill Publications Co., New York), Vol. 125, No. 8, Aug, 1981, pg. 37.

^{**}In order to be certified, the observer must "read," consecutively, 25 samples of black smoke, and 25 of white smoke from (randomly) 0 to 100% opacity. No reading may be in error by more than 15 percentage points, and the average error in both the black & white categories must each be less than 7.5 percentage points as compared to a calibrated in-stack transmissometer.

FIGURE B-II-3 $\text{SO}_2\text{-SO}_3$ SAMPLING SYSTEM



- (1) 100 mL OF 80% ISOPROPYL ALCOHOL (IPA) IN WATER ABSORBS SO_3
- (2) 100 mL OF 3% H_2O_2 IN WATER ABSORBS SO_2 AS WELL AS ANY SO_3 NOT ABSORBED BY THE FIRST IMPINGER
- (3) 100 mL OF 3% H_2O_2 IN WATER. THIS IS A BACK-UP TO IMPINGER #2. IF IMPINGER #2 SHOULD BECOME SATURATED, #3 WILL ABSORB ANY SO_x THAT GETS THROUGH #2.
- (4) THIS EMPTY TRAP HELPS KEEP THE PUMP DRY.

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membrane between adjacent tubes) during an earlier boiler shutdown. A 1/2 inch pipe was welded over each hole so that a sample of furnace gas could be drawn through it from outside the boiler. Furnace gas tap locations are shown in Figure B-II-4.

During a gas-tap test, furnace gas was pulled, under vacuum, from the furnace and through a 10 to 20 foot, 3/8" stainless steel (SS) coil where the gas was quickly quenched from its more than 2000°F temperature to nearly ambient temperature. This quenched the reaction thus preserving for analysis, the incompletely reacted species present at the sampling point.

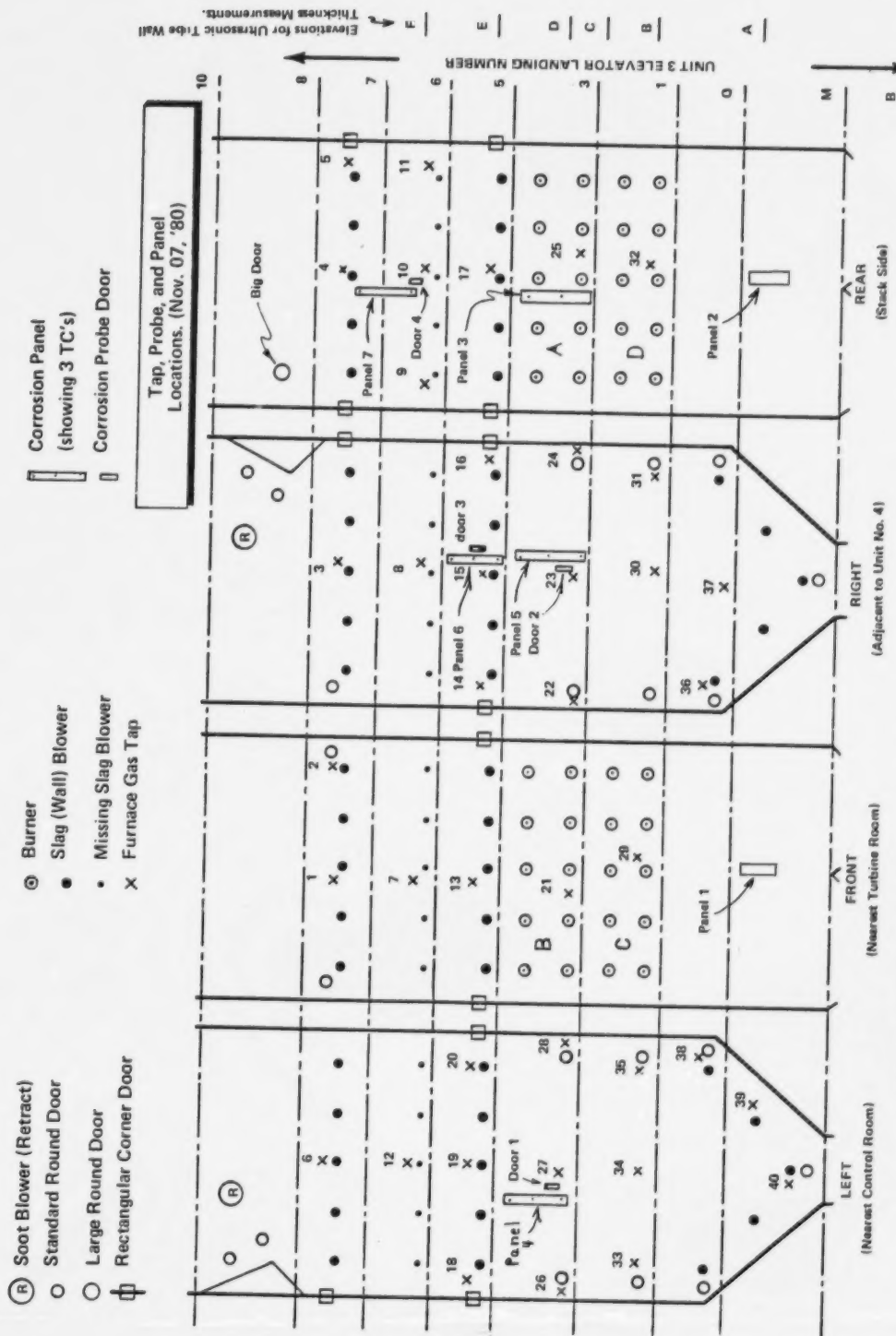
Of course, this caused water condensation in the sampling lines which in turn may have absorbed some NO_x and produced a falsely low NO_x reading. However, for the purpose of these tests, in which corrosive environments were being screened, little emphasis was placed on the NO_x reading.

From the SS coil, the sample flowed through about 200 feet of 3/8" "Polyflo" brand plastic tubing to one of the two glass wool filters. The remainder of the sampling and analysis train was the same as described earlier in this report, except that instead of a heated, gas-conditioning box, an unheated impinger bottle, filled with glass wool was used as a filter/water trap. The line between the sample point and this filter was 200 feet long, rather than four feet as was the case when the flue duct was sampled. This was because during the multi-point sampling procedure in the furnace gas tests (40 sampling points), it was impractical to place a conditioning box or filter close to each sampling port. Instead, only two filters were used, and these remained in one place. A 200 foot "Polyflo" line was used to bring the sample to the filter (one line for each filter). The other end of the long sampling line was carried and connected to each gas tap in turn. Only one line could be sampled at a time. Meanwhile, the other sampling line would be purging with the next waiting sample. This saved a great deal of time since each of the 40 samples, required 3-4 minutes to reach the analytical instruments. Because of the length of the line connecting the sampling port with the filter, it was impractical to heat it. This was not expected to interfere with the analyses of the species of interest (e.g., CO, O₂).

III. RESULTS OF CHARACTERIZATION TESTS

A. Summary of Test Conditions and Independent, Controlled Test Parameters

Before presenting the results, it would be helpful to know the conditions under which each test was performed, as well as a few other parameters for cross referencing the test information.



Views As Seen By An Observer Looking At The Walls From Outside The Boiler.
MILL CREEK No 3.

FIGURE B-II-4 TAP, PROBE AND PANEL LOCATIONS

By far, the most common type of testing was the analysis of flue gas composition at the economizer outlet duct just upstream of the air heater. Table B-III-1 lists boiler operating conditions and the resulting flue gas composition for each of the tests performed, in order by test number and date. In Table B-III-2, tests done under similar operating conditions are grouped together for easy comparison.

B. Flue Gas Data (Continuous Monitors)

The results of all flue gas tests are summarized in Table B-III-1 which also shows the boiler operating conditions for each test. Analysis of NO was done by the chemiluminescent (NOCHEMI) method as well as by the non-dispersive infrared (NDIR) method. Both results are shown on Table B-III-1, but generally, the NOCHEMI values, which originated from a newer and more reliable analyzer are considered by the instrument operators to be the more reliable.

Ideally, in order to evaluate (one at a time) each of the NO_x control parameters investigated, it was desirable to choose (in turn), one parameter of interest, and hold the others constant while the one of interest was varied from test to test in order to see its effect on NO_x. However, in practice, it was rarely possible to hold any of the operating parameters constant for very long and this complicated the job of data interpretation. Nevertheless, some relationships did become apparent.

1. NO_x vs. O₂

The rate of many chemical reactions can be decreased by decreasing the supply of one or more reactants. Hence, one would expect that decreased excess air flow (i.e., decreased oxygen concentration in the flue gas) would cause a corresponding decrease in NO_x emissions. Therefore, a plot of flue gas NO_x (corrected to 3% O₂) vs. O₂ would be expected to show a trend toward lower NO_x at lower O₂.

The families of curves in Figures B-III-1 through B-III-3 show NO_x vs. O₂ for various sets of conditions as indicated on each figure. Clearly, they show (as expected) that NO_x emissions are generally decreased as O₂ (excess air) is decreased.

This and other trends shown in the figures are summarized below:

- o NO_x decreases as excess air decreases (Figures B-III-1 through B-III-3).
- o NO_x decreases as load decreases (Figure B-III-2).
- o NO_x is more responsive to changes in air flow at higher loads than at lower loads. (In Figure B-III-2, the full load curve is steeper than medium load curves.)

TABLE B-III-1
SUMMARY OF CONDITIONS TESTED & RESULTING FLUE GAS ANALYSIS
(IN ORDER BY TEST NUMBER AND DATE)

TEST	DATE	LOAD	FUELFLOW	XSAIR	INNER	OUTER	SPIN	FGR	FRNGPTRN	BIAS	O2	NOX	NOCHEMI	NONDIR	CO2	CO
1	03/21/79	393	258	7	36	51	10	0	30	0	4.79	450	434	463	15.1	83
2	03/21/79	399	263	7	36	51	10	0	30	0	3.82	402	390	418	15.3	110
3	03/23/79	389	243	3	36	51	10	5	50	0	3.70	343	337	427	15.4	161
4	03/23/79	385	244	3	36	51	10	5	100	6	2.77	316	313	311	15.5	191
5	03/23/79	385	246	7	36	36	10	5	50	0	3.61	349	346	345	15.5	199
6	03/23/79	387	247	3	36	36	10	5	60	6	2.81	327	323	318	15.6	249
7	03/26/79	395	260	7	36	51	10	0	60	6	3.48	394	389	416	15.7	192
8	03/26/79	404	261	3	36	51	10	0	60	6	2.82	361	355	387	15.6	213
9	03/29/79	293	179	7	36	51	10	7	70	0	4.42	534	522	334	15.0	379
10	03/29/79	299	181	3	36	51	10	7	70	6	2.99	280	273	299	15.2	332
11	03/29/79	304	183	7	36	51	10	7	70	6	5.05	294	284	326	14.0	348
12	03/29/79	300	183	7	36	36	10	7	70	6	5.22	289	282	317	13.7	353
13	03/29/79	297	182	7	36	36	10	9	70	0	4.83	308	301	341	13.7	390
14	03/30/79	168	119	7	36	51	10	9	90	0	8.57	297	288	402	13.6	474
15	03/30/79	166	116	3	36	51	10	9	90	0	6.74	230	223	256	13.8	431
16	03/30/79	400	273	7	36	51	10	0	30	0	4.23	415	412	390	15.4	255
17	04/03/79	392	270	7	36	36	10	0	30	0	5.11	455	448	446	15.1	221
18	04/05/79	303	207	7	36	51	10	5	70	0	5.42	375	369	393	14.6	221
19	04/05/79	308	203	5	36	51	10	5	70	0	4.55	348	346	371	14.4	201
20	04/05/79	326	216	7	36	71	10	5	70	0	4.54	365	360	390	14.2	184
21	04/05/79	325	218	7	36	51	10	5	70	0	4.24	358	353	380	14.1	178
22	04/05/79	326	216	5	36	71	10	5	80	6	4.17	353	347	368	13.8	159
23	04/06/79	197	136	7	36	51	10	9	70	0	6.56	320	314	517	14.6	222
24	04/06/79	203	142	6	36	51	10	9	80	6	6.01	312	302	341	14.0	272
25	04/06/79	204	135	6	36	71	10	9	80	6	6.03	289	283	311	13.9	251
26	04/06/79	199	143	6	36	36	10	9	80	6	5.77	286	279	315	14.1	260
27	04/07/79	407	277	7	36	51	10	4	50	0	4.45	399	392	404	15.1	18
28	04/07/79	409	277	7	36	36	10	3	50	0	4.41	414	408	442	13.7	20
29	04/07/79	408	272	3	36	71	10	3	50	0	3.96	408	402	466	13.5	19
30	04/07/79	404	273	3	36	71	10	3	60	6	3.43	398	391	476	13.4	19
31	04/07/79	404	271	7	36	36	10	3	70	0	4.60	457	450	468	13.4	19
32	04/07/79	402	272	7	36	51	10	3	70	0	4.44	440	433	457	14.1	14
33	04/07/79	400	272	7	36	71	10	3	70	0	4.44	440	433	437	13.9	13
34	04/07/79	402	272	3	36	71	10	3	80	6	4.01	399	390	421	14.3	19
35	04/07/79	401	272	3	36	71	10	3	80	6	3.97	400	392	425	14.5	11
36	04/07/79	401	272	3	36	51	10	3	80	6	4.82	366	363	389	14.7	44
37	04/09/79	308	207	7	36	51	10	0	70	0	3.11	02	352	425	14.1	641
38	04/23/79	175	219	7	36	51	10	0	30	0	6.22	304	301	598	15.6	15
39	04/23/79	251	219	7	36	51	10	0	30	0	5.80	379	375	628	15.1	92
40	04/23/79	392	337	7	36	51	10	0	30	0	5.69	517	512	512	16.3	21
41	10/08/80	400	346	7	44	29	23	0	30	0	6.48	503	493	512	16.3	21
42	10/08/80	400	334	3	44	29	23	0	30	0	4.52	466	463	493	16.3	21
43	10/08/80	410	336	7	44	29	23	0	50	0	3.13	415	603	603	24.6	343
44	10/08/80	405	335	3	44	29	23	0	50	0	5.31	507	503	503	16.0	20
45	10/08/80	402	340	3	44	29	23	0	70	0	4.15	461	461	461	16.2	22
46	10/08/80	401	334	3	44	29	23	0	70	0	5.11	515	512	512	14.9	138
47	10/09/80	403	321	7	44	29	23	0	70	0	10.20	467	486	486	15.1	74
48	10/10/80	399	300	7	44	29	23	5	70	0	4.82	494	493	493	15.1	74
49	10/15/80	418	353	7	44	29	23	0	70	0	4.82	494	493	493	15.1	74

KEY TO ABBREVIATIONS: See next page.

KEY TO ABBREVIATIONS USED IN TABLE B-III-1

LOAD:	Megawatts, electric (net)
FUELFLOW:	Coal flow ... kPounds/hour
XSAIR:	Qualitative description (on a scale of 1 to 9) of the amount of excess air delivered to the combustor. 1: Much less excess air than normal ----- (<~4% O ₂) 7: Normal (Note that normal is 7, not 5) ----- (~4% O ₂) 9: More excess air than normal ----- (>~4% O ₂)
INNER } OUTER } SPIN }	Each has units of "percent of full open". Describes the average positions of the burner vane and register controls.
FGR:	Flue gas recirculation. A qualitative description of the amount of flue gas being recirculated to the hopper. 0: None (FGR fan off) 9: High (fan on and dampers open)
FRNGPTRN:	Firing pattern is a qualitative term (on a scale of 0 to 100) for describing how the total fuel flow is distributed among the several rows of burners. The higher the value, the lower is the fraction of the total fuel flow in the upper burners. It is expected that high "FRNGPTRN" values will result in low NO _x . 0: All bottom burners are off 50: All burners are on equally 100: All top burners are off
BIAS:	Describes the way the air fuel ratio varied from burner row to burner row. High bias was expected to give low NO _x . 0: All burners had the same air fuel ratios (no bias) 9: High bias. Air/fuel ratio is much higher in upper burners than in bottom ones.
NOXCHEMI:	NO _x (as measured by the chemiluminescent method) has units of ppm(v) at 3% O ₂ , dry.
NOCHEMI:	NO (as measured by the chemiluminescent method) has units of ppm at 3% O ₂ , dry.
NONDIR:	NO _x (as measured by the nondispersive infra-red method) has units of ppm at 3% O ₂ , dry.
CO2:	percent CO ₂ at 3% O ₂ , Dry.
CO:	ppm at 3% O ₂ , Dry.

TABLE B-III-2

TEST NUMBERS* GROUPED BY TEST CONDITIONS

Outer Air Registers % Open		35	50	70	35	50	70	35	50	70	35	50	70	35	50	70
Firing Mode	Bias	Full Load (370-420 MW)			Medium Load (250-330 MW)			Low Load (165-205 MW)			Low Load (165-205 MW)			Low Load (165-205 MW)		
		Normal Air			Normal Air			Low Air			Normal Air			Low Air		
All Burners On	No	5N	3L	29N	43N											
	Yes	28N	27M													
One Top Mill Off	No	44N	32N	33N	45N											
	Yes	46N														
One Bottom Mill Off	No	48H														
	Yes	49N														
Both Top Mills Off	No	17N	1N		41N	2N										
	Yes	40N	16N													
Both Top Mills Off	No															
	Yes															

*Letter suffixes refer to amount of flue gas recirculation (None, Low, Medium, High - as explained on next page).

**The damper positions for Tests 38 and 39 were not recorded.

For additional notes, see next page.

NOTES FOR TABLE B-III-2

FLUE GAS RECIRCULATION (KEY TO LETTER SUFFIXES)

- o During some tests, flue gas was recirculated to the hopper. The amount of flue gas so recirculated is qualitatively indicated by a letter suffixed after each test number in Table B-III-2. The letters stand for: None, Low, Medium, and High.

EXCESS AIR (LIMITS OF CONTROL SYSTEM)

- o For low excess air tests, the air flow was decreased first on the bottom mills by going to full range on the bias thumb-wheel control. Then, if further decrease in excess air was desired, the boiler master control was used. However, if air was decreased beyond a certain preset limit on any one mill, the automatic control system would decrease the fuel flow to keep the fuel/air ratio within preset limits and a load reduction would result. This was an undesirable situation, and was avoided by the operators.

BIAS CONTROL SYSTEM

- o Bias was generally controlled through the fuel/air bias control thumb-wheel on each mill controller while still in automatic control. Under these conditions, the amount of bias possible was quite small. The following is a qualitative description of the terms used to describe whether or not (yes or no) biased fuel/air ratios were used during each test.

No = Little or no Bias

(i.e., Fuel/air ratios were nearly equal for all burners.)

Yes = Significant Bias

(i.e., Upper burners have significantly smaller fuel/air ratios than lower burners.)

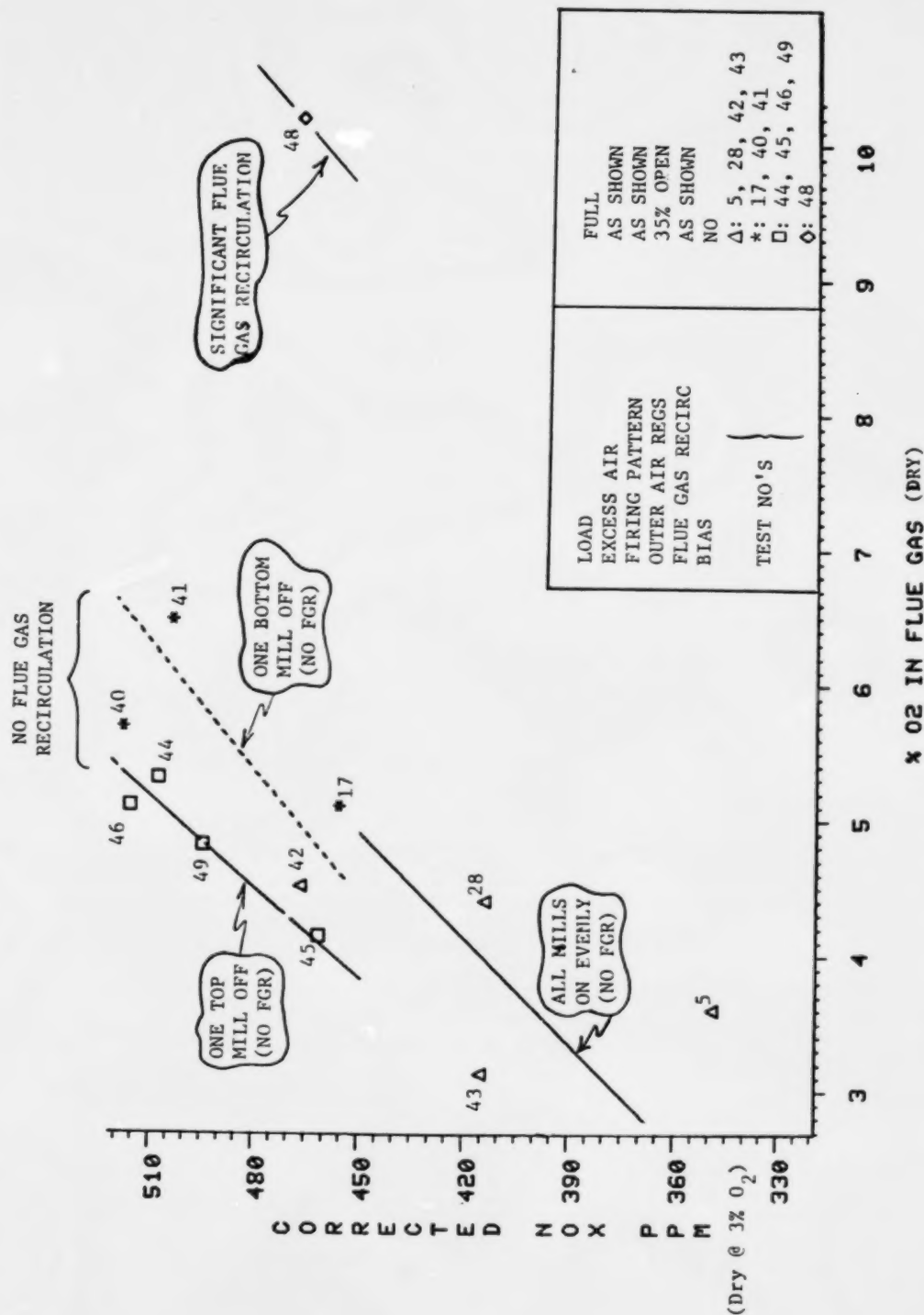


Figure B-III-1. NO_x vs. Flue Gas O₂ for Various Firing Patterns

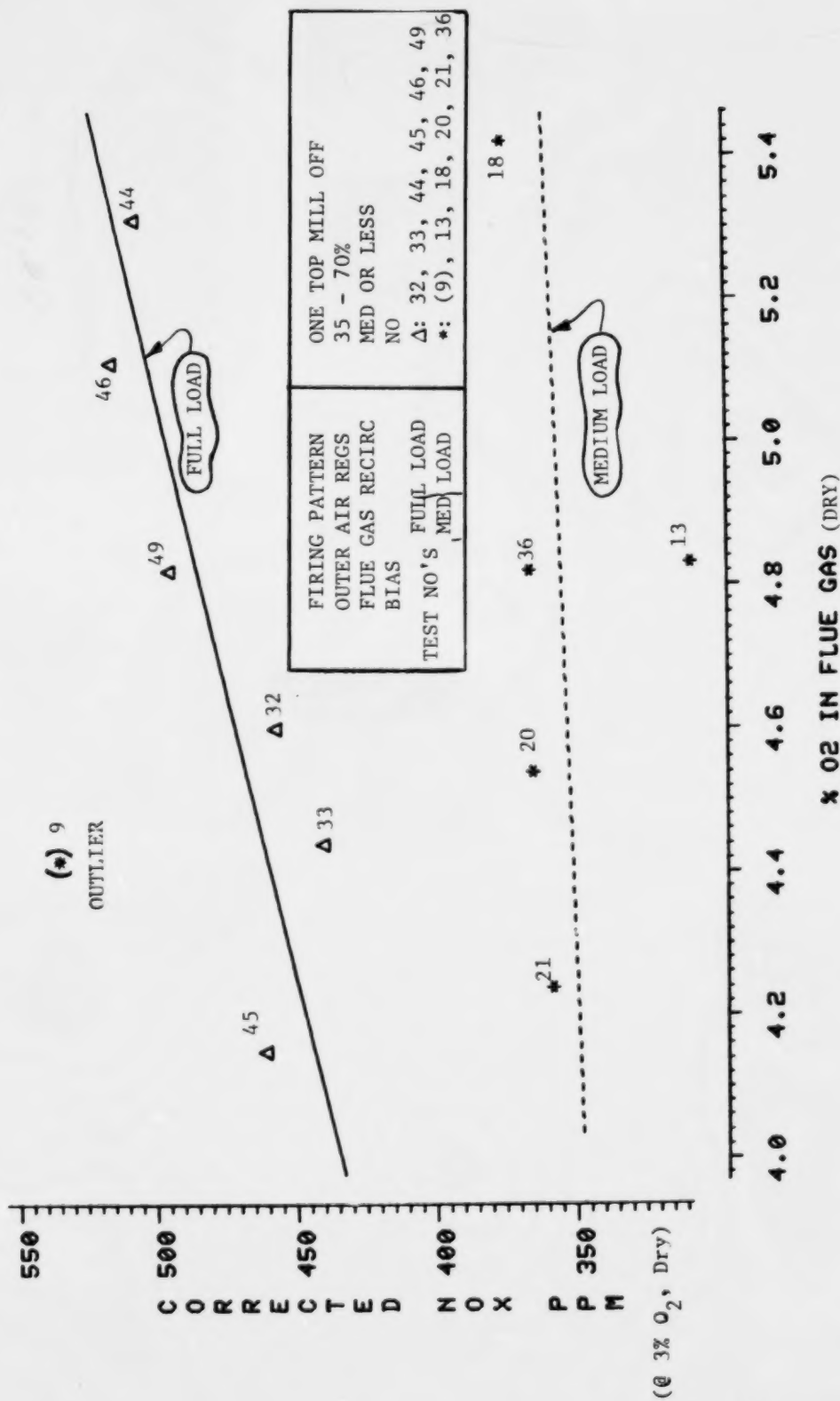


Figure B-III-2. NO vs O₂ for Different Loads

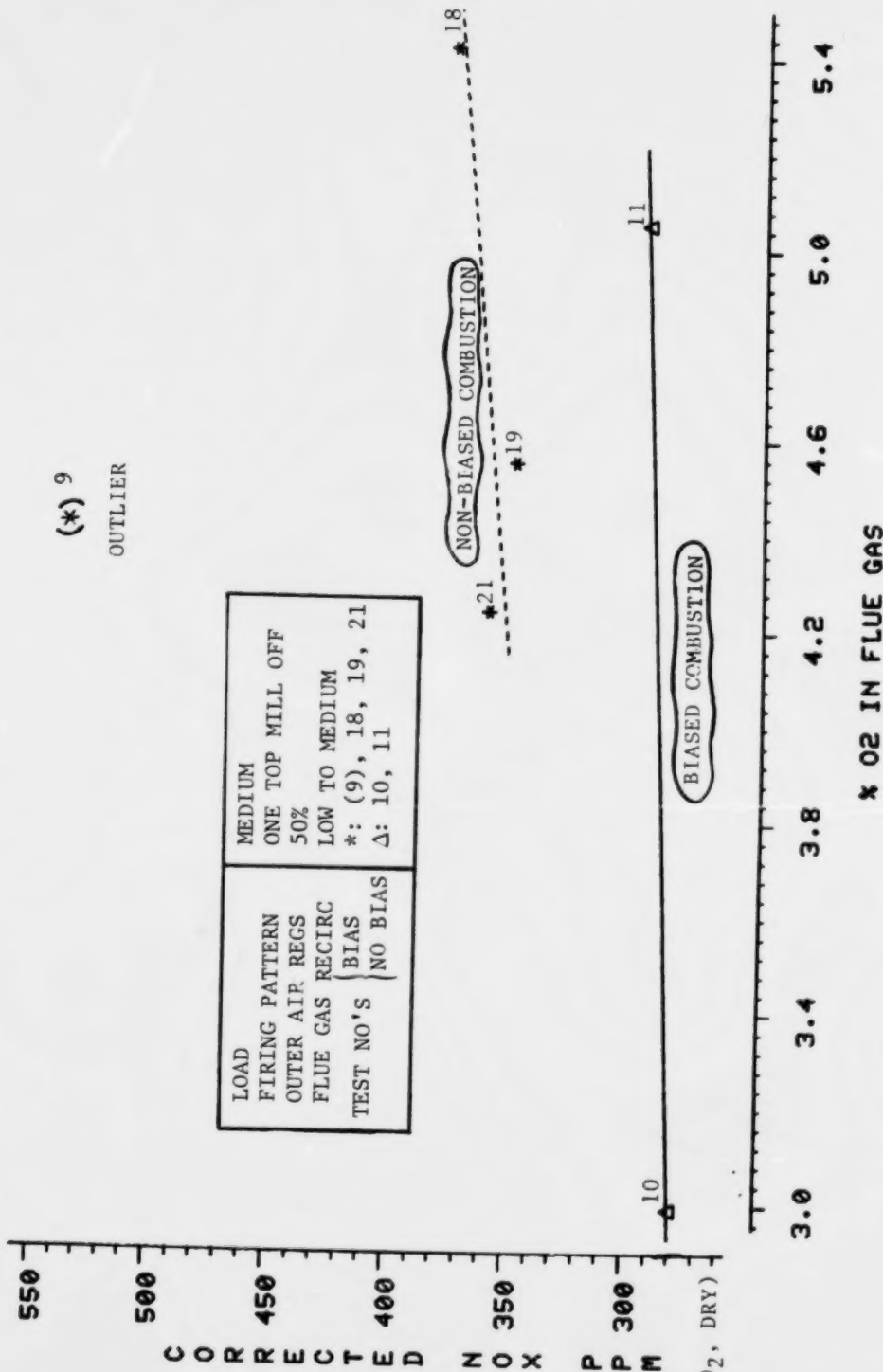


Figure B-III-3. NO_x vs. O₂ for Biased and Non-Biased Combustion

- o NO_x decreases as bias is increased (Figure B-III-3).
- o NO_x is relatively insensitive to firing pattern (i.e., fuel distribution) (Figure B-III-1).

From an operating point of view, there is a safe limit beyond which the O_2 flow should not be further reduced. Hence, during the testing period, O_2 was decreased only to the point where CO emissions began to increase. This occurred well in advance of problems such as loss of combustion efficiency or excess slugging. In this regard, the CO monitor installed for these tests proved to be a useful tool for decreasing excess air flow to optimum levels for NO_x control.

2. NO_x vs. Load

NO_x emissions generally decreased as load was decreased because, as load is reduced, the ratio of heat input rate to heat transfer area decreases, resulting in a cooler flame and lower NO_x production. However, load is not generally considered as a method for NO_x control since economics and customer demand for electric power do not allow boiler operators to change load at will. In rare cases, boilers may be derated as a last resort for NO_x control. Figure B-III-2 shows the effect of load on NO_x .

3. NO_x vs. Firing Pattern (i.e., Fuel Distribution)

For the few cases tested, Figure B-III-1 seems to show that NO_x emissions are relatively insensitive to the tested fuel distributions among the several rows of burners.

4. NO_x vs. Outer Air Register Settings

The burners at Mill Creek No. 3 are capable of introducing secondary air in two stages (called "inner" and "outer" air). The inner air is first to mix with the fuel and primary air, then the outer air completes the combustion. If the outer air is closed, then virtually all of the combustion air must enter through the inner air nozzles and the staging effect is lost.

During the boiler characterization period, tests were performed to evaluate the effects of various air register settings. Observers noticed that the outer air register settings had a visible effect on flame shape. As the outer air was closed, the shroud of air surrounding the inner flame was lost and the long thin flame that was observed, began to flare out into a more wide-spread flame having increased turbulence, which, as expected, produced increased NO_x emissions when flue-gas recirculation was not used (see Figure B-III-4).

Only a small range of outer air settings was tested due to flame instability at certain register settings (especially at low loads). Over the range tested, the effect of outer air on NO_x

LOAD	EXCESS AIR	FIRING PATTERNS	BIAS	FGR RATE	TEST NO'S.
FULL	NORMAL	One top mill off	NO	NONE	Δ: 32, 33, 44, 46, 49
	LOW (<~4% O ₂)	One bottom mill off			*: 1, 16, 17, 40
		All mills on	YES	NONE	□: 8, 31
LOW	NORMAL	Both top mill off	YES	LOW	◇: 4, 6
				HIGH	#: 24, 25, 26

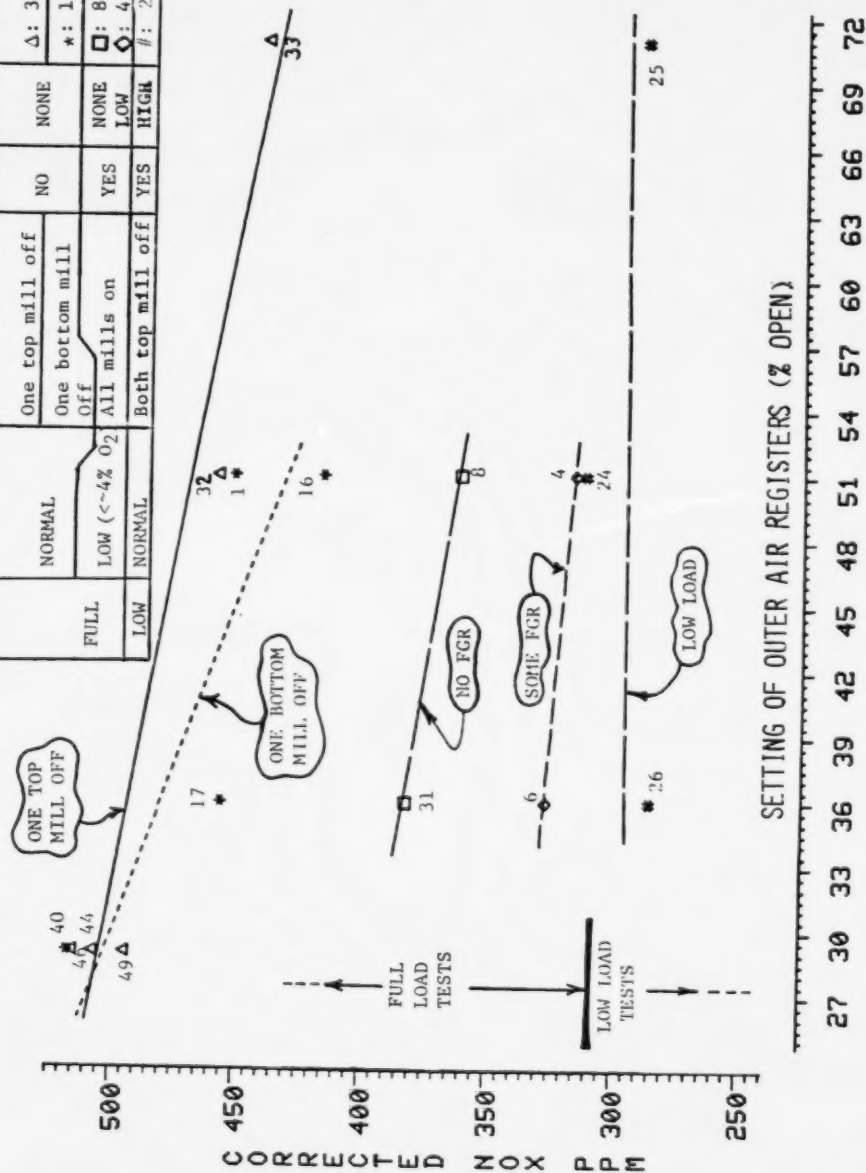


Figure B-III-4: NO_x vs Outer Air Registers for Various Loads, Firing Patterns, and Flue Gas Recirculation Rates.

was very small. Since adjustment of the registers is a laborious manual job, it cannot be done often during normal boiler operations. (For example, it is not practical to adjust the registers each time a load change occurs). Therefore, the registers were set and locked into the positions giving the greatest flame stability for all loads.

5. NO_x vs. Bias (i.e., Spatial variation of fuel/air ratio)

A furnace, operating with a higher fuel/air ratio at the bottom burners than at the top, is said to be operating under biased combustion. Each group of burners has its own bias (fuel/air ratio) control, but the range on that controller is small and bias could only be evaluated qualitatively. Figure B-III-3 compares one group of tests in which all fuel/air ratios were the same (no bias) with a group having higher fuel/air at the bottom than at the top. The group using biased firing showed decreased NO_x emissions.

6. NO_x vs. Flue Gas Recirculation (FGR)

On this boiler, flue gas was occasionally recirculated back into the furnace through the hopper for temperature control, and to a lesser extent for slag control. The boiler was designed to allow flue gas to be recirculated into the windbox for NO_x control,* but, since NO_x emissions have always been satisfactorily low at this boiler, that part of the system was never used. (It could not be tested.) The "FGR-to-hopper" system was working, and although not specifically designed for NO_x control, it did have a limited effect on NO_x emissions as shown qualitatively in Figure B-III-4 (which shows a decrease in NO_x emissions as flue gas is recirculated through the ash hopper).

7. Summary of Factors Affecting NO_x

A statistical analysis package was used to evaluate which of the boilers' operating parameters had the greatest effect on NO_x emissions. About 15 parameters were used to describe (to the computer) each of the 49 test conditions. The analysis showed that only about 5 of those parameters seemed to be related to NO_x emissions. They are listed below in order of effectiveness for NO_x** control (most effective on top). Note: This is a qualitative comparison.

*Flue gas recirculation to the windbox decreases NO_x emissions by introducing the relatively inert flue gas through the burners thus displacing combustion air in the early stages of combustion. This "stretches" and cools the flame.

**Surprisingly, the computer analysis found that some of the boiler control parameters affecting NO_x also affected CO₂ emissions.

- o Load
- o Excess air
- o Fuel flow
- o Firing pattern (i.e., fuel distribution)
- o Bias (for the range tested, the effects may be insignificant)

C. Furnace Gas Taps

During Test No. 47, furnace gas was sampled from about forty locations along the furnace wall so that locally corrosive (chemically reducing) environments (high CO, low O₂) could be identified. The sampling locations along with the corresponding oxygen and carbon monoxide values are shown in Figure B-III-5. The spatial variations of other component concentrations are listed in Table B-III-3. This test (No. 47) was performed at normal, full load operation with one top mill (B) off (same conditions as for flue gas Test No. 46 described earlier).

A local environment is considered to have a high potential to corrode metal tube surfaces if it is chemically reducing (low O₂ or high CO). The data show that most such points are in and around the burner zone.

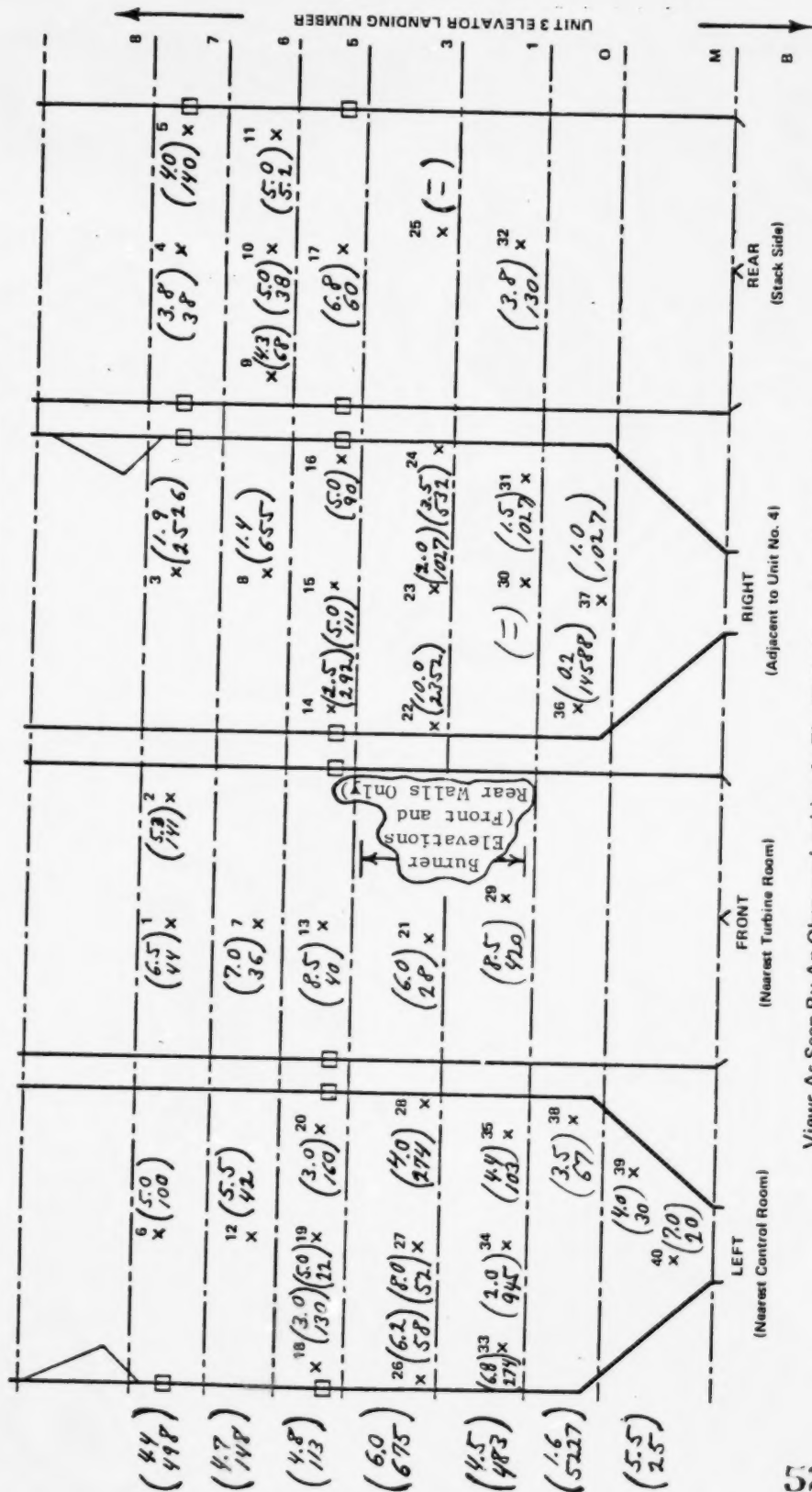
The reader should be advised that during this gas sampling and analysis, CO and O₂ readings varied over wide ranges in short time periods. It was common for oxygen at a single point to change from 1% to 4% and then back to 1% within 10 or 15 seconds. In a similar time period, the CO could vary from 100 ppm to 3,000 ppm and back again. This confirms that within the furnace, steady state conditions do not exist. Instead, the flame continuously flickers and changes shape from second to second, thus complicating the jobs of data recording and analysis. Hence, the gas-tap data here has a wide error bar and should be considered to be qualitative rather than absolute.

D. SO₂ - SO₃ Data

The coal used at Mill Creek produces about 12,000 Btu/pound during combustion and contains about 4% sulfur (3.3 pounds [= 0.103 lb-moles] of sulfur/MBtu). Assuming complete conversion to SO₂ implies that the untreated flue gas will contain 0.103 lb-moles (6.6 pounds) of SO₂ per MBtu. According to EPA F-factors, the fuel burned produces 9820 standard cubic feet of dry, undiluted flue gas per MBtu. Therefore, after using the ideal gas law to calculate the volume occupied per lb-mole of SO₂, and adjusting for dilution, it follows that the dry flue gas, when diluted with air (to contain 5% oxygen, as was typical during tests where SO₂ was measured), would contain 3070 ppm SO₂.

Actually measured values were about 2,000 ppm SO₂ and 20 ppm SO₃, showing as expected, that most of the sulfur in the coal is converted to flue gas SO₂ and is delivered to the scrubber where sulfur compounds are removed. The remainder of the coal's sulfur may have escaped detection by the measurement method used, or may have been

Figure B - III - 5:0₂ and CO₂ Readings at Furnace Walls



Views As Seen By An Observer Looking At The Walls From Outside The Boiler.
MILL CREEK No 3.

NOTE: Top number in parenthesis is O₂% (dry), bottom value is CO ppm (dry, actual). Values at left of page indicate average for row.

Table B-III-3. Furnace gas tap results (in order sampled)

FURNACE GAS TAP NUMBER	O ₂ (PCT)	NO _x (CHEMI) (PPM)	NO (CHEMI) (PPM)	AS MEASURED	
				CO (PPM)	CO ₂ (PCT)
21	6.00	378.	370.	28.	13.21
1	6.50	350.	360.	44.	12.73
2	5.30	363.	380.	141.	14.46
3	1.90	472.	475.	2526.	16.86
4	3.80	475.	468.	38.	15.23
5	4.00	470.	460.	140.	15.23
22	10.00	334.	324.	2352.	16.31
6	5.00	440.	460.	100.	14.97
23	2.00	450.	450.	1027.	16.58
7	7.00	360.	365.	36.	11.79
8	1.40	510.	498.	655.	16.86
9	4.30	427.	410.	68.	14.46
24	3.50	330.	329.	532.	16.03
10	5.00	480.	470.	38.	13.95
11	5.00	475.	480.	52.	14.20
25	16.00	301.	300.	188.	5.65
12	5.50	432.	425.	42.	13.95
26	6.20	385.	380.	58.	13.21
13	8.50	320.	300.	40.	11.34
17	8.00	365.	355.	52.	12.26
14	2.50	352.	350.	292.	16.31
28	4.00	370.	328.	274.	14.71
15	5.00	450.	450.	111.	14.20
16	5.00	380.	370.	90.	13.70
17	6.80	424.	420.	60.	12.73
18	3.00	460.	450.	130.	15.23
19	5.00	469.	461.	22.	13.70
30	0.0	165.	160.	0.	16.03
29	8.50	225.	278.	420.	11.34
31	1.50	340.	311.	1027.	14.71
20	3.00	370.	350.	160.	15.50
32	3.80	311.	270.	130.	14.97
33	6.80	330.	246.	274.	11.79
34	2.00	430.	420.	945.	14.46
35	4.40	380.	380.	103.	14.46
36	3.50	370.	350.	67.	14.97
37	1.00	300.	310.	1027.	17.14
38	0.20	250.	270.	14588.	16.58
39	7.50	340.	350.	20.	10.89
40	4.00	360.	380.	30.	14.71

LEAK

retained in the ash. (Verified by coal analysis for ash, and ash analysis for sulfur ... see Appendix B.)

IV. CONCLUSIONS AND DISCUSSION OF CHARACTERIZATION TESTS

The extra instrumentation temporarily installed for the characterization tests allowed the operating controls to be evaluated beyond the limits normally possible, and yielded valuable information about how NO_x emissions can be controlled through combustion modifications (CM).

A. NO_x Formation and Abatement Mechanisms

NO_x is formed when nitrogen and oxygen react at high temperatures. Its control is achieved by removing the available oxygen (and/or nitrogen), and/or decreasing the high flame temperatures that sustain some of the reaction paths.

Oxygen concentration can be decreased by decreasing excess air flow. Alternatively, air flow may be selectively decreased in the vicinity of the ignition point so that volatile, highly reactive fuel-nitrogen released at the ignition point will lock onto molecules other than O_2 and form products more desirable than NO_x . The remainder of the excess air may be added further downstream. This is known as staged combustion.

Flame temperature can be decreased by:

- o Increasing the size of the furnace to provide more heat transfer area. (Not viable as a retrofit.)
- o Staging the combustion process (by not adding the necessary combustion air all at once). Thus, the fuel will burn more slowly with a longer, less intense flame. (Staging also forces the reaction along a path favoring N_2 rather than NO_x by depriving intermediate nitrogen species of oxygen in the early stages of combustion.) However, not all boilers are capable of sustaining staged combustion on a routine basis.
- o Decreasing load. This works similar to increasing the size of the furnace in that it results in more heat transfer area per rate of heat input. This is not a recommended method of NO_x control since load is usually fixed by demand and cannot be varied at will.

B. Recommended Approaches for NO_x Control and Reduction

Several controllable combustion parameters (each involved with one or more of the above principles) were selected for study as possible NO_x controls. These were:

- o Load
- o Firing pattern
- o Outer air register settings
- o Flue gas recirculation
- o Bias
- o Total excess air flow

Load reduction results in decreased NO_x emissions. However, since load must follow demand it was not considered for NO_x control.

Similarly, firing pattern (which burners are on) is usually determined by routine mill maintenance schedules and factors other than NO_x emissions and therefore cannot usually be freely changed for NO_x control.

On some boilers, a single elevation of burners can be deprived of fuel while operating on air only. When this is a top row, it behaves like an over-fire air supply and may result in decreased NO_x emissions. However, at this boiler it is not possible to shut down just a single row of burners and the firing patterns tested had little effect on NO_x emissions, especially during low excess-air firing. Change in firing pattern, therefore, is not a recommended method for NO_x reduction on this boiler.

The outer air register setting had only a small effect on NO_x emissions for the range tested. Opening these registers from 35% to 50% caused NO_x reductions of about 10% (40 ppm). Increasing the setting from 50% to 70% while not improving the NO_x situation, could cause the flame to become unstable, especially at low loads. Since it is impractical to change these registers every time a load change occurs, they should be permanently set at the position recommended by the manufacturer, that gives the greatest overall flame stability for all loads. That setting seems to be 50% open, and their use for NO_x control is not recommended.

The flue gas recirculation system on Mill Creek No.3 was designed to return some of the flue gas to either the furnace hopper (for steam temperature control and slag control) or to the burners (for NO_x control). At this boiler, flue gas was recirculated only when needed for temperature control. The control system for recirculating flue gas to the burners (through the windbox) was not needed and therefore had not been maintained. It was thus inoperative during the characterization tests, and could not be evaluated for NO_x control.

However, the limited effect of flue gas recirculation through the hopper was evaluated on this boiler. At full load, with no other NO_x controls in use, flue gas recirculation through the furnace hopper decreased NO_x emissions by 12% (about 50 ppm). Therefore, on this unit, when operating conditions allow, flue-gas recirculation is a possible method for limited NO_x control.

Bias refers to the deviation of the fuel/air ratio controller from its normal set point. Tests of bias were usually done in conjunction with low-air tests. The first step in decreasing the air flow for testing was to decrease the air flow to the lower burners. This was done by use of the bias control associated with those burners. In this way, the lower burners became fuel-rich, and the top ones fuel-lean (a condition similar to staged combustion).

Since the bias controllers on the boiler had only a small range of operation, the effect on NO_x was also small, but nevertheless was significant. Hence, for NO_x control, whenever conditions allow, the top burners should be operated fuel-lean, and the bottom ones fuel-rich. At full load this may result in a 15% decrease (about 45 to 55 ppm) in NO_x emissions.

By far, of the controls tested, excess air has the greatest effect on NO_x , and with proper instrumentation, is easiest to control. At full load, a decrease of flue gas oxygen content from 4% to 3% resulted in a NO_x reduction of about 40 ppm (10%). (During the full-load characterization tests, the plant normally operated with 5% O_2 in the flue gas. This is somewhat higher than these tests indicated was necessary.)

Still greater NO_x reductions are possible by further reductions in excess air, but for this, extra instrumentation is required because CO emissions and combustion efficiency could be adversely affected if excess air is reduced too much. With the extra instrumentation (e.g., a CO monitor), one could extend the margin of comfort for operating the furnace with decreased excess air.

It is recommended that without a CO monitor, excess air should be decreased until flue gas oxygen is no lower than 3 to 3.5 percent. (The oxygen monitors must be calibrated frequently to insure that the true value is no lower than the indicated value.)

The control system on this boiler is programmed to keep the oxygen within certain limits regardless of any action by the operator. Hence, during the characterization tests, the range over which excess air could be varied was tightly constrained, and, for the range tested, reductions in excess air flow caused NO_x emissions to decrease by only 10-20%. It is felt that a wider control range on excess air could help to increase the achievable NO_x reduction to the limits imposed by carbon-on-ash losses, and combustibles (unburned carbon) in the flue gas.

The average NO_x emissions for all "as-found" full-load tests (Test Numbers 3, 5, 27, 28, 29, 42) was 393 ppm (0.54 lbs NO_x as NO_2 per

MBtu). This includes only tests in which all burners were on, and excess air flow was normal. Some of these tests used flue gas recirculation, since this, when necessary for temperature control, was a normal operating procedure. The reader should notice that for these "as-found" tests, the average NO_x emissions were well below the applicable NSPS limit of 0.7 pounds NO_x (as NO₂) per MBtu* (301 ng/J). By decreasing the excess air and biasing its distribution as much as the limited range on the controller would allow (Test Numbers 4, 6, 8, 30, 31), the average NO_x emissions were decreased still further, to 356 ppm (0.49 lbs NO_x as NO₂/MBtu).

*Conversion factor: $\left(\frac{\text{Pounds NO}_x \text{ (as NO}_2\text{)}}{\text{MBtu}} \right) = (\text{ppm NO}_x \text{ (at 3\% O}_2\text{, dry)}) \left(\frac{1}{731.4} \right)$

PART C

LEVEL 1 ENVIRONMENTAL ASSESSMENT

I. PURPOSE AND OPERATING CONDITIONS FOR THE LEVEL 1 TEST

A Level 1 test is a screening study to evaluate the effect that a process has on its environment. In this case, the process is the combustion of high-sulfur coal in a utility boiler (specifically, LG&E's Mill Creek Unit No. 3) designed for minimum NO_x emissions. This part of the report covers the Level 1 work.

A. Purpose of the Level 1 Test

The Level 1 testing procedure developed by EPA allows a wide variety of process emissions to be assessed. It is the first phase in a 3 phased approach designed to evaluate emissions from a point source.

The Level 1 procedure was developed by the Process Measurement Branch of the EPA's Industrial Environmental Research Laboratory.* It (the Level 1 procedure) encompasses all effluent streams from a process. At Mill Creek No. 3, inlet streams were also sampled so that, if desired, a mass balance could be performed on the plant to separate inlet stream effects from process effects.

This test was designed to answer the following questions within an accuracy factor of 3:

- o What pollutants are being emitted?
- o What effluent streams are toxic?
- o How toxic are those streams?
- o What is the mass emission rate of each pollutant?

These questions were answered through sampling and analysis of all pertinent effluent streams: solid, liquid, gaseous, and particulate. Analysis was physical, chemical and biological. Some inlet streams were also sampled in order to separate process contributions from those due to the inlet streams thus helping to determine how inlet streams are changed chemically by the process and redistributed to the various outlet streams.

*"IERL-RTP Procedures Manual: Level 1 Environmental Assessment (Second Edition)." EPA-600/7-78-201, October 1978.

B. Operating Conditions During the Level 1 Test

This test was an evaluation of normal, NSPS operation of this boiler, and as such, involved no unusual or special operating conditions. Normal full load operating procedures (as summarized in Table C-I-1) were followed for the boiler. Those conditions are summarized below. (Details are included in Appendix A.)

TABLE C-I-1		
SUMMARY OF BOILER OPERATING CONDITIONS DURING THE LEVEL 1 TEST		
Load (electric output):	418	MW
Steam Flow (production):	2,755,000	pounds/hour
Steam Pressure:	2410	psig
Steam Temperature:	1004	°F
Fuel Consumption (coal):	360,000	pounds/hr
Burners on:	A,C,&D Mills (only "B" mill is off)	
Flue Gas Recirculation	Off	
Burner Adjustments	Locked	
Spin Vanes	23% of full open**	
Inner Air Registers	43% of full open**	
Outer Air Registers	29% of full open**	
Excess Air	Normal	
Heat Input Rate	4,233 MBtu/Hr***	

Mill Creek No. 3 is capable of full load when using only 30 of its 40 burners. When not needed, the burners to be shut down are chosen arbitrarily. For the purpose of this test, the test supervisor chose to shut down the top two rows of burners on one of the walls. (The alternative was to shut down a bottom double row.)

*Btu: British Thermal Unit.

**Each burner has three manual controls ("inner", "outer", and "spin"), each with an adjustment range of 19 notches (full closed = 1, full open = 19). Each number given here represents the average position of the lever for the burners in use. Note that in the case of the spin vanes, spin increases and spin flow decreases as the spin vanes are closed.

***A post test calculation based on the "F" factor method (to be discussed later ... see Appendix F) gives 4,125 MBtu/hr while another type of post test calculation (Appendix D) based on fuel feed rate (Appendix A) and Exxon's analysis of Btu content of coal (Appendix B) yields 4,340 MBtu/hr. The value used here is the average of the two methods.

Since the Level 1 test lasted eighteen hours, soot blowing continued as usual (intermittently) during the test in order to prevent boiler "slagging."

A detailed record of the boiler's operating conditions was kept during this test (Test No. 49) and may be found in Appendix A.

II. SAMPLING PROCEDURES

The Level 1 procedures were modified slightly so that the only effluent streams sampled were those thought to be affected by "low-NO_x" operation. Some inlet streams were also sampled in order to allow incoming contaminants to be factored out.

Table C-II-1 lists the various sampling points with reference to Figure B-II-1 which shows the general layout of the unit. Generally, the sampling procedures listed in the EPA Level 1 procedures manual were followed.* Containers used to hold the samples were cleaned prior to use by approved methods: generally acid cleaning followed by a solvent rinse (usually methanol) and a final rinse with distilled, deionized water.

A. Flue Gas at Boiler Exit (Economizer Outlet)

1. Continuous Monitors (Permanent Gases)

Flue gas was analyzed as described in Part B of this report. Particulate matter and water were removed from the flue gas by filters and permeation tube dryers, respectively. Then the samples were cooled and pumped through "Polyflo" brand plastic tubing to the mobile laboratory, containing the continuous gas analyzers. Typically, only the "permanent" gases (O₂, CO₂, etc.) and major pollutants (NO_x, CO, etc.) were analyzed in this way. Other gases (e.g., hydrocarbons, as well as the permanent gases) were analyzed by gas chromatography (GC).

2. Gas Chromatography

Gas chromatography (GC) was used to detect the most difficult-to-analyze flue gases. All on-site GC field work was done on a three-detector, Perkin-Elmer model Sigma 2(B) gas chromatograph with a Spectra-Physics SP-4100 computing integrator.

GC analysis was performed according to the procedures outlined in the Level 1 manual with very few exceptions. The few deviations from the Level 1 procedures manual were made on advice

*"IERL-RTP Procedures Manual: Level 1 Environmental Assessment (second edition)." EPA - 600/7-78-201, October, 1978.

TABLE C-II-1

SAMPLES TAKEN FOR LEVEL 1 ANALYSIS		
	Sample*	Analysis
A	Flue Gas (as it leaves the furnace)	O ₂ , CO, CO ₂ , H ₂ , N ₂ , hydrocarbons, cyanide derivatives, sulfur-complexes, ammonia type compounds, oxides of nitrogen
B	Coal Belt (7 hours before being burned - as fired)	Proximate, ultimate, sulfur, heat content, bio-assay
C	Sluice water from quench tank overflow (ash leachate)	Chemical assay, bio-assay
D	Flue Gas (at ESP inlet)	Particulate loading & size distribution, organic and inorganics, condensibles, trace elements, bio-assay
E	Flue Gas (at ESP outlet)	Particulate loading
F	Water (inlet to sluice tank)	Chemical assay (used for blank control on Sample "C")
G	Fly ash (at ESP hopper)	Chemical assay, bio-assay

*See Figure B-II-1.

from equipment manufacturers and GC experts. Gas samples were taken from the flue duct (just upstream of the air heater) in an unheated glass sampling vessel designed for GC grab samples. After sampling, the vessel was taken to the GC where, a few minutes later, a sample was removed from it (by syringe) and injected into the GC for analysis.

All columns were supplied by Supelco Company, and all calibration gases except for the hydrocarbon standard mixture (which was supplied by Scott Co.), were supplied by Matheson Company.

Table C-II-2 summarizes the GC operating conditions and calibration standards. Details may be found in Appendix E.

3. SO₂ and SO₃ Analysis

A modified version of EPA Methods 6 and 8 was used to analyze flue gas for SO₂ and SO₃. A sketch (Figure B-II-3) and description of that system may be found in Section II.C.2 of Part B of this report.

In addition to the flue gas samples, for quality assurance, an audit solution supplied by EPA was also titrated. The results may be found in Table C-IV-6.

B. Fuel Samples (from Feed to Coal Silos)

Because of the large volume of coal needed for the biological tests, it was impractical to take samples close to the burners. Instead, 75 pounds of crushed coal were taken from the belt feeding the silos. The sample was taken before 9:00 a.m. on the day of the Level 1 test (October 15, 1980). Together, the silos hold enough coal to operate the boiler at full load for about seven hours. This means that the coal sampled was actually burned that afternoon and thus is fairly representative of the coal burned throughout the Level 1 test.

After collecting the sample, it was divided, sealed in plastic bags, and shipped to the various laboratories for analysis as described on Table C-II-3.

C. Sluice Water (Bottom-Ash Leachate)

At the Mill Creek plant, water is used to flush slag (bottom ash) and economizer ash to a waste pond. (The precipitator catch (fly ash) is removed, dry, by a vacuum system.) For the purpose of the Level 1 environmental assessment, it was desirable to know what effect the slag had on the water used to flush it out. Therefore,

TABLE C-II-2

GAS CHROMATOGRAPHY SPECIFICATIONS

Method	Species of Interest	Calibration Standard	Column	Temperature & Conditions	Detector
A	CO CO ₂ O ₂ H ₂ CH ₄ N ₂	~166 ppm ~13.3% ~3.78% ~0.97% ~26 ppm Balance *	Carbosieve S 7' x 1/8" SS 100/120 mesh size	350C for 4 min., then 250C/min. to 1750C. 40 cc/min. Inject 1 cc	Dual Thermal Conductivity (Hot Wire) Detector
B	H ₂ S SO ₂ COS Thiophene Methyl Mercaptan Ethyl Mercaptan	1.5 ppm 2123 ppm 5 ppm 1.8 ppm 0.96 ppm 0.92 ppm *	36' x 1/8" (OD) Teflon with 12% polyphenyl either and 0.5% H ₃ PO ₄ on 40/60 mesh Chromosorb T	500C for 5 min. then 100C/min. to 1000C	Single Flame Photometric Detector
C	NH ₃ HCN Cyanogen	190 ppm 130 ppm 170 ppm *	6' x 1/4" (OD), x 2 mm (ID) Glass with 60/80 mesh Poropak Q	400C Isothermal	Dual Thermal Conductivity Detector
D	Light Hydrocarbons C ₁ - C ₅	Methane 15.1 ppm Ethane 14.8 ppm Propane 15.7 ppm Butane 15.2 ppm Pentane 16.2 ppm Hexane 17.1 ppm Heptane 13.1 ppm *	6' x 1/4" (OD), x 2 mm (ID) Glass w/ 60/80 mesh Poropak Q	600C for 4 min., then 200C/min. to 1100C. Detector @ 2000C. 25 cc/min. Inject 1 cc	Single Flame Ionization Detector
E	Heavy Hydrocarbons C ₁ - C ₇		6' x 1/4" (OD), x 2 mm (ID) Glass w/ 20% SP 2100 on 80/100 mesh Supelcoport	Isothermal @ 300C. Detector @ 2000C. 20 cc/min. Inject 1 cc	Single Flame Ionization Detector

Notes:

In all cases, the carrier gas was helium.

*Brackets indicate a single blend in one cylinder with nitrogen making up the balance.

TABLE C-II-3

COAL SAMPLE DISTRIBUTION AND ANALYSIS

Laboratory	Analysis
Battelle Labs (50 pounds)	Biological assay using aquatic systems
Research Triangle Institute (RTI) (4 pounds)	Biological assay using non-aquatic systems
ER&E, Baytown (4 pounds)	Physical analysis such as proximate and ultimate analysis including sulfur, nitrogen, moisture, ash, heat content (Btu), and other standard ASTM tests
ER&E, Linden (4 pounds)	Chemical analysis

TABLE C-II-4

SLUICE WATER DISTRIBUTION & ANALYSIS

Laboratory	Analysis
Battelle Columbus Laboratories (25 gallons)	Biological assay using aquatic systems
Research Triangle Institute (2 gallons)	Biological assay using non-aquatic systems
ER&E, Linden (2 gallons)	Chemical analysis

it was desirable to obtain a water sample that had been in contact with the slag for as long as possible.

Since it was not possible to sample the effluent sluice stream (ash and water) downstream of the clinker grinder, the next best way to sample the slag leachate was to catch the overflow from the quench tank (Figure B-II-1 is a general schematic of the sampling locations).

Prior to the Level 1 tests, the slag hopper and quench tank were emptied and cleaned so that any subsequent samples taken from there would be known to be a result of the test. Once the test began, the discharge gates were closed and the quench tank was allowed to fill with slag and make-up water (which presumably leached solubles out of the slag). After the tank filled, and several hours into the test, the hot overflow was sampled. The sample was divided, packed in ice, and distributed for analysis according to Table C-II-4.

D. Flue Gas at the Precipitator Inlet

Gas entering the electrostatic precipitator (ESP) fly ash removal system was sampled for particulate, including: grain mass loading, size distribution, condensibles, chemical composition, and biological toxicity. In addition, the flue gas was analyzed for O₂, N₂, CO₂, and H₂O.

1. Method 5 (Particulate Loading)

EPA Method 5 was used to determine particulate loading at the ESP inlet as well as at the outlet, thus allowing evaluation of the ESP efficiency. Sampling and analysis was performed by "Entropy Environmentalists" Company. Pertinent sections of their report may be found in Appendix F.

The test method (Method 5) is summarized in the following paragraphs. A full description of most EPA methods, including Method 5, may be found on page III - Appendix A-1 of the "Standards of Performance for New Stationary Sources."* Figure C-II-1 is a schematic of the Method 5 system.

During a traverse of the flue duct, particulate laden gas entered the sampling nozzle isokinetically thus assuring that the stream was undisturbed by the probe and that a representative sample was obtained. The sample was then collected under

*"Standards of Performance for New Stationary Sources - A Compilation as of January 1, 1980," Pedco Environmental, Inc. Jan. '80. EPA numbers: EPA 340/1-77-015, EPA 340/1-79-001, EPA 340/1-79-001a, EPA 340/1-80-001.

vacuum through the heated probe and filter where particulate matter was captured and saved to be weighed later. Next, the clean gas passed through a set of impingers designed to allow water to be trapped and measured, and then finally through a dry gas meter where the sampled volume was measured.

The total concentration of particulate matter in the flue gas entering the precipitator was determined by weighing the "catch" on the Method 5 filter.

2. Source Assessment Sampling System (SASS)

In addition to the Method 5 system for sampling particulate matter, particulate was sampled at the precipitator inlet by the Source Assessment Sampling System (SASS) as well. Besides providing information on grain loading, SASS also provides size distribution data for the entrained particles. Also, through subsequent analysis, SASS yields a great deal of information about the chemistry of that stream. However, unlike the Method 5 train, the SASS train is too bulky to traverse the stream being sampled. Instead, particulate matter was sampled at a single point near the centroid of one of the two ducts and near a point of average velocity as determined by a previous velocity traverse. A schematic of the SASS train is shown in Figure C-II-2.

The SASS train can be used to determine total particulate loading and size distribution (in four ranges). Other stages in the SASS train capture volatile organics, condensables, and trace elements which were then shipped to the laboratory for analysis. As with the Method 5 train, sampling occurred isokinetically thus ensuring a representative sample. However, the resulting flow rate was about 8% slower than the design rate and may have shifted the cyclone cutpoints upward by about 20%.* It was hoped that enough sample would be captured to allow some of the catch, not used for chemical analysis, to be used for bio-assays.

Following the test, the sampling train was removed to the field laboratory. Wash-down and sample recovery were done the day after sampling. All samples and washings were transferred to precleaned containers in accord with Level 1 procedures. The samples were shipped to Exxon, Linden on the day following the wash-down, for analysis.

3. O₂, CO₂, N₂, and H₂O Determination

Calculations used in isokinetic sampling require information concerning the temperature, pressure, and molecular weight of the gas being sampled. Hence these parameters were measured and recorded.

O₂, CO₂, and N₂ were determined by Orsat (EPA Method 3), while water content, initially assumed (as per EPA procedures) to be

*See "Validity of Cyclone Cutpoints" in Appendix H.

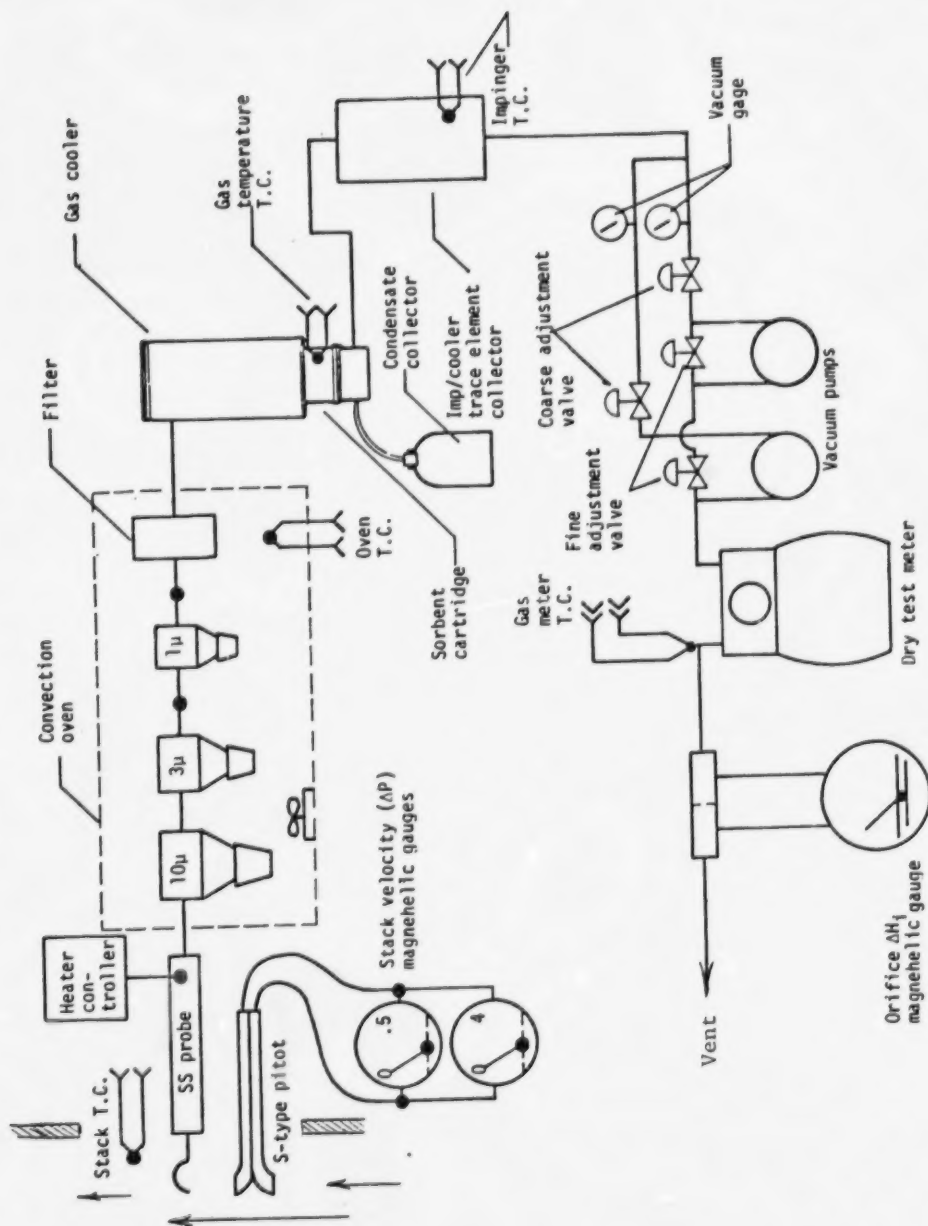


Figure C-II-2. Schematic of SASS.*

*D. E. Blake, "Source Assessment Sampling System: Design and Development," U.S. Environmental Protection Agency Publication #EPA-600/7-78-018, February, 1978, pg. 4-5.

8%, was determined more accurately a short while after the test by measuring the condensate captured in the Method 5 train. (The Method 5 result (presented later) was 7.07 volume percent H₂O.)

- E. Flue Gas At The Precipitator Outlet As at the precipitator inlet, dust in the flue gas leaving the precipitator was sampled by EPA Method 5. The SASS train was not used at the precipitator outlet. Otherwise, sampling and analysis for particulate matter (dust) was done in the same way as at the inlet. (See the previous section (D) of this report.)

- F. Make-up Water (Inlet to Sluice Tank)

Water was sampled at the inlet to the sluice tank. This was to be used for comparison with water taken from a stream leaving the sluice tank, thus allowing the evaluation of any changes in the water due to its contact with the bottom ash as it passed through the quench tank. The sample (2 gallons) was packed in ice and sent to Exxon for chemical analysis.

- G. Fly Ash (From ESP Hopper)

During normal boiler operation, the heaviest, stickiest ash (bottom ash) eventually falls into the slag hopper (quench tank) at the bottom of the boiler. The lighter, finer ash (fly ash) is carried by the flue gases as fly ash to "clean-up" systems downstream of the combustion zone.

The stickiest fly ash (highest sulfur content) is believed to deposit on the superheater and reheater tube plattens and eventually falls into the economizer hopper which, according to plant operators, is thought to collect less than 10% of the total fly ash. The majority of the fly ash is carried downstream where more than 90% of it is collected in the hoppers of the electrostatic precipitator (ESP). The only fly ash referred to in this section was that sampled from the ESP hoppers.

Prior to the test, all ESP hoppers (3 rows of about 5 hoppers each, in each of the two ESP sides) and sampling ports were emptied. The hoppers were then allowed to fill with ash generated during the test. A composite sample, consisting of ash from several hoppers in each of the three rows was collected. Ordinary metal trash cans (new) were used to collect and store the ash until it cooled, whereupon it was transferred and sealed in clear plastic bags for shipping. The distribution of the sample is summarized in Table C-II-5.

TABLE C-II-5	
FLY ASH DISTRIBUTION AND ANALYSIS	
Laboratory	Analysis
Battelle Columbus Laboratories (60 pounds)	Biological assay using aquatic life systems
Research Triangle Institute (4 pounds)	Biological assay using non-aquatic systems
ER&E, Baytown (4 pounds)	Physical and chemical analysis
ER&E, Linden (4 pounds)	Chemicals analysis

III. ANALYTICAL PROCEDURES

Generally, sample analysis was carried out according to the EPA Level 1 procedures. Using the continuous monitors described in Part B of this report, the gaseous phase of the flue stream leaving the boiler was the only sample analyzed in the field. All other samples were shipped to various laboratories for analysis.

IV. RESULTS OF LEVEL 1 ENVIRONMENTAL ASSESSMENT

A. Flue Gas Leaving The Boiler

1. Continuous Monitors

Most of the sample collecting activities related to this Level 1 test were accomplished in less than twelve hours. During this time (as during the characterization tests, discussed earlier), flue gas was sampled from a point between the economizer and the air pre-heater. The samples were pumped to the continuous monitors for about twenty minutes of each hour and the data were recorded. During this test, CO readings drifted upward (probably due to instrument drift) and as such should be

considered to be maximum rather than true values. Table C-IV-1 summarizes the gaseous emissions measured during this test.

TABLE C-IV-1

FLUE DUCT GAS ANALYSIS (BY VOLUME, DRY BASIS)
(Avg. for 09:40 - 21:30 on 10-15-80)

O ₂ (%)	NO _x (ppm)	NO (ppm)	CO (ppm)	CO ₂ (%)
(as measured)	(corrected to 3% O ₂)			
4.78	494	493	74	15.1

2. Gas Chromatography

Flue gas analysis by gas chromatography (GC) proved to be much more difficult than expected. Problems with calibration of the various columns and detectors were among the most difficult obstacles.

Calibration gases had been prepared and bottled offsite a few months prior to this test. Many of these calibration standards contained less than 100 ppm of the species of interest. Such small concentrations may have reacted in the cylinder, or been adsorbed by the cylinder walls before the test, and may thus explain why some of the calibration species could not be detected by the GC.

Integrated plots generated during calibration and sample analysis by the GC are shown in Appendix E. Trouble with the flame photometric detector circumvented sulfur compound analysis by GC. Table C-IV-2 lists the significant GC results based on the GC information in Appendix E.

3. SO₂ and SO₃ Analysis

SO₂ and SO₃ were analyzed by titrating solutions which had absorbed these compounds from known volumes of flue gas as described in Part B of this report.

The sample discussed here was collected on 10-16-80 after setting up the boiler in the desired operating mode similar to that used for the bulk of the Level 1 sampling effort.

TABLE C-IV-2

GC RESULTS (FLUE GAS AT ECONOMIZER OUTLET)

Analytical Method (From Table II-2)	Component	Response Factor**		Concentration in Flue Gas
		(Peak Area) Units	Unit of (Concentration)	
A PERMANENT GASES	H ₂	2200/percent		0.0005%
	O ₂	1.375 cm/percent (pk ht/percent)***		5.5%
	N ₂	119000/percent		82%
	CO	560/ppm		507 ppm
	H ₂ O	Interference		-
	CO ₂	170,000/percent		13%
	CH ₄	calibration gas not detected		-
B SULFUR COMPOUNDS	SO ₂	} Equipment problems prevented this analysis.		-
	COS			
	H ₂ S			
	CH ₃ -SH			
	(CH ₃) ₂ -SH			
	Thiophene			
C NITROGEN COMPOUNDS	HCN	} Calibration gases not detected		< 100 ppm*
	NCCN			
	NH ₃			
D LIGHT HYDRO- CARBONS	nC ₁	1240/ppm		<10 ppm*
	nC ₂	2310/ppm		<10 ppm*
	nC ₃	3250/ppm		<10 ppm*
	nC ₄	9760/ppm		4 ppm****
	nC ₅	17188/ppm		<10 ppm*
	nC ₆ ****	} Calibration peak not positively identified		<10 ppm*
	nC ₇ ****			<10 ppm*
E HEAVY HYDRO- CARBONS	nC ₁	660/ppm		not found (<25 ppm*)
	nC ₂	2579/ppm		
	nC ₃	3307/ppm		
	nC ₄	4530/ppm		
	nC ₅	5302/ppm		
	nC ₆	5458/ppm		
	nC ₇ ****	8000/ppm		

*Not found (the lower detectability limit follows the "less than" sign).

**For a 1.0 cc injection (sample size was always 1.0 cc).

***Valid when integrator attenuation is AT = 64.

****Peak has not been positively identified.

For this test, all chemicals were mixed fresh, and an EPA audit sample was analyzed concurrently. A summary of the raw field data from the analysis is presented on Table C-IV-3.

The number of "moles" of SO₂ or SO₃ captured in each impinger is found from the following formula. (The audit sample vial can be treated as an impinger catch.)

$$\left(\begin{array}{c} \text{Number} \\ \text{of} \\ \text{Moles} \end{array} \right) = \left\{ \frac{\left(\begin{array}{c} \text{Volume} \\ \text{of} \\ \text{Titrant} \end{array} \right) \left(\begin{array}{c} \text{Normality} \\ \text{of} \\ \text{Titrant} \end{array} \right) / (2)}{\left(\begin{array}{c} \text{Fraction} \\ \text{of Impinger} \\ \text{Solution Titrated} \end{array} \right)} \right\}$$

(This assumes pure "blanks".)

The weight of SO₂ or SO₃ captured is simply the number of moles multiplied by the molecular weight. Then, correcting the volume of gas sampled ("canned" values were supplied with the audit sample) gives results in units of weight per cubic meter, which can be corrected to parts per million by application of the ideal gas law. Further conversions can be performed to correct to a standard oxygen concentration (3% O₂) or to terms of "mass emissions per heat input." (See conversion factors, Appendix D.) The final results are displayed in Table C-IV-4.

B. Flue Gas Entering and Leaving Precipitator

1. Total Particulate Matter

EPA Method 5 sampling and analysis for total particulate loading at both the inlet and outlet of the ESP was performed by Entropy Environmentalists, Inc. under contract to ER&E. Pertinent sections of their report may be found in Appendix F, which is summarized below and in Table C-IV-5 which indicates that the ESP has a collection efficiency of about 99%.

It is interesting to note that the coal analysis (Appendix B) indicates that the fuel is 13% ash. Therefore, the 360,000 pounds of coal fired per hour during this test would be expected to produce 46,800 pounds of ash per hour. However, Table C-IV-5 indicates that only 27,000 to 34,000 pounds of fly ash per hour are leaving the boiler in the flue gas stream entering the ESP. Therefore the remainder must be slag, bottom-ash, or economizer ash.

TABLE C-IV-3

SO₂-SO₃ SAMPLING AND ANALYSIS - FIELD DATA

	Duct Sample	Audit Sample
Impinger Solutions 1st (SO ₃) 2nd and 3rd (SO ₂)	100 mL of 80% IPA in H ₂ O 100 mL of 3% H ₂ O ₂ in H ₂ O (each)	
Titrant Composition for SO ₃ analysis for SO ₂ analysis	0.01 normal BaCl ₄ in IPA 0.1 normal NaOH in H ₂ O	
Indicator for SO ₂ analysis for SO ₃ analysis	Methyl orange Thorin	Methyl orange Thorin
Volume shown on meter Meter temperature Barometric pressure	21 liters 98°F (=558°R) 29.2 in Hg	-
*Volume of Titrant 1st Impinger (SO ₃) 1st Time 2nd Time 2nd Impinger (SO ₂) 1st Time 2nd Time 3rd Impinger (SO ₂)	1.0 mL 8.2 mL 0.1 mL	9.2 mL 9.2 mL

*For the duct sample, this is the amount of titrant used to titrate 1/5 of the sample. In the case of the audit vial, it is the amount needed to neutralize exactly 1/5 of a solution containing 12.5 mL (not 5 mL) of the audit sample.

TABLE C-IV-4

SO₂ AND SO₃ CONCENTRATIONS*

	Duct Sample (Assumes 5% O ₂ (Dry) in Duct)			Audit Sample
	$\frac{\text{mg}}{\text{DSCM}^{**}}$	ppm (dry, at 5% O ₂)	$\frac{\text{lbs}^{*****}}{\text{MBtu}}$	$\frac{\text{mg}}{\text{DSCM}^{**}}$
SO ₃	103(1)	31(2)	0.082(3)	--
SO ₂	6795	2547***	5.42	2805****

(1)(2)(3) Sample calculations may be found in Appendix D.

*Dry basis at actual O₂ concentration. The interested reader may convert to units of pounds per hour, or other units. The necessary data (stack gas flow rate, etc.) may be found in the appendices. Similarly, data for conversion to a wet basis or to a standard dilution (e.g., 3% O₂) may also be found in the appendices.

**Dry standard cubic meters. Standard conditions are defined as 68°F (20°C) and 1.0 atmospheres.

***This is in good agreement with the control room reading of 2548 ppm (measured at the scrubber inlet). (See Appendix A.)

****The values supplied with the audit sample indicate that the correct result is 2593 mg/DSCM.

*****See Appendix D (the basis - dry or wet, and % O₂ - are both irrelevant here).

TABLE C-IV-5

SUMMARY OF METHOD 5 RESULTS

Test Pairs	A		B		C	
Test Number	Inlet 1	Outlet 4	Inlet 2	Outlet 5	Inlet 3	Outlet 6
Grains/DSCF	3.96	0.0525	4.40	0.0389	4.76	0.0153
Pounds/Hour	27,000	422	34,000	319	30,000	120
Pounds/MBtu	6.1	0.0963	8.5	0.0792	7.5	0.0303
Collection Efficiency	98.7%		99.1%		99.7%	
Stack Flow (DSCF/Min)	785,000	938,000	895,000	957,000	734,000	915,000
Excess Air*	30%		43%		40%	
Heat Input (MBtu/Hr)*	4400		4000		4400	
Moisture (%)	6.6	6.3	7.1	6.7	7.5	7.3
CO (vol %) Dry	0.0		0.0		0.0	
CO ₂ (vol %) Dry	13.9		12.2		12.6	
O ₂ (vol %) Dry	4.9		6.5		6.1	
N ₂ (vol %) Dry	81.2		81.3		81.3	

*Based on Gas Measurements at the Precipitator Outlet.

For calculations used in the particulate tests, gas composition was found by Orsat Analysis while heat input and excess air were calculated from "F" factors and related formulas.

2. SASS (Precipitator Inlet Only)

The Source Assessment Sampling System (SASS) was used only at the inlet to the precipitator. Following the test, the sampling system was washed, and the samples were shipped to ER&E's Linden laboratories for analysis. Plans were made to ship any excess particulate samples from Linden to other laboratories for biological analysis. This section summarizes the SASS results. Details are provided in Appendix H.

Inductively Coupled Plasma Emission Spectroscopy (ICPES) was used to analyze the XAD-2 resin and the impinger solutions as well as the particulate samples of the SASS train for metals, while cold vapor atomic absorption (AA) was used for mercury. Metals data is summarized in Table C-IV-6 (details are presented in Appendix H). Special attention was given to the metals on EPA's list of 13 priority pollutants for wastewater (top of Table C-IV-6).

TABLE C-IV-6

METAL DATA ON STACK EMISSIONS FROM LOUISVILLE SASS TEST
(RESULTS REPORTED IN $\mu\text{g/g}$)

Element	10 + 3 μm Cyclones	1 μm Cyclones	Coal	Fly Ash	Make Up Feed Water	Sluice Water
Ag	<4.2	<5.0	<6	(12) ^b	<0.0025	<0.0029
As	67 ^b	350 ^a	<25	90 ^b	(0.011)	(0.018)
Be	(2.7) ^b	20 ^b	(3.2) ^b	8.2 ^b	<0.0006	<0.0007
Cd	57	110	<11	(18)	<0.0047	<0.0053
Cr	140	260	<1.8	110	0.024	<0.0008
Cu	110	190	9.7	96	<0.0002	<0.0002
Hg	0.058	0.0021	0.0020	0.025	<0.0001	<0.0001
Ni	240	330	<15	200	<0.0064	<0.0073
Pb	(47) ^b	190	<19	<21	<0.0078	<0.012
Sb	(69) ^b	(72) ^b	(58) ^b	(67) ^b	<0.015	<0.017
Se	<17	280 ^b	<25	<21	<0.010	<0.012
Tl	(22) ^b	87 ^b	<11	45 ^b	<0.0048	<0.0055
Zn	820	3100	62	780	0.061	0.11
Al	98000	120000	14000	92000	0.021	1.6
Ba	540	800	58	570	0.075	0.11
Ca	30000	26000	5400	30000	72	91
Co	<3.4	40 ^a	(9.2)	<4	<0.002	(0.0035)
Fe	110000	79000	11000	120000	<0.0011	2.4
K	24000	26000	3200	23000	4.2	6.6
Li	79	100	6.8	75	0.0065	0.03
Mg	5500	7900	770	5300	14	16
Mn	330	430	45	320	<0.0001	0.025
Mo	100 ^b	320 ^b	<9.8	96 ^b	(0.0072)	0.052
Na	4100	4600	800	3500	25	28
P	900	4200	<54	1100	(0.051)	0.13
Si	210000	120000	66000	100000	0.73	0.54
Sn	<13	(38) ^b	<19	<16	<0.0078	<0.009
Sr	200	300	20	190	0.30	0.29
Ti	4800	6200	330	4400	<0.0005	0.13
V	410	1200	<11 ^b	480	<0.0045	0.069

a Data less reliable due to significant spectral or background interferences.

b Data unreliable due to strong interferences or weak signals.

() Means that the value is less than 3 times the ICPES detection limit or the blank value. These results may not be significant since they are more easily affected by background fluctuations.

< Means that the printed value represents the lower limit of detection for the element in that particular sample.

Most metals (largest amount by mass) were present in the particles, but less than 5% of the total metal was found in the 1 μ m cyclone. However, the metals appeared to be more concentrated on these small particles than on the larger (3 and 10 μ m) ones. Mercury concentrations, as expected, were higher in the impingers (which are designed to catch volatile elements such as As, Hg, and Sb). Except for mercury, other volatile metals were not found in significant amounts. (It was not considered unusual to find high levels of Fe, Ni, Mn, Mo, and Cr which may have been leached from the stainless steel components of the sampling system.)

ICPES metal analysis showed that most metals had generally higher μ g/g concentrations on the smaller particulates. However, less than 5% of the total metal emissions were collected in the 1 micron cyclone. In general, the levels of most toxic metals were low (<100 mg/SASS test) and near or below the ICPES detection limits.

Microscopic analyses show that the SASS cyclones are effective in size fractionation of particulate material.

Most of the particulate matter consisted of large size particles. Seventy percent of the particulate mass was greater than 10 μ m in equivalent aerodynamic diameter and total particulate loading was 8.0 lbs/MBtu; (similar to the more reliable Method 5 inlet results already presented on Table C-IV-5). In this report, Method 5 data is used for total particulate loading while SASS is used for particulate size distribution and other information.

Electron microscopy revealed that the SASS cyclones were efficient at separating the fly ash into size fractions and that the dominant shape was spherical. (Fly ash samples collected in the ESP hoppers had a rougher surface than those captured by the SASS train at the ESP inlet.) There seemed to be a bimodal size distribution with the larger particles averaging about 20 μ m, and the smaller ones 3-4 μ m in diameter. The composition of the particulate was mostly silicates (which may have originated from clays).

X-ray analysis of the fly ash typically showed silicon, lithium, aluminum, potassium, and iron with smaller amounts of calcium, sulfur, and titanium. (Sulfur was the most abundant element detected by x-rays in the coal samples.) About 10% of the particulate SASS sample contained particulates rich in iron, sulfur, and titanium. These elements, detected by x-ray energy dispersive analysis were also detected by ICPES.

TABLE C-IV-7

SASS TOTAL ORGANICS

Sample	(ng of organics)/(Joule of fuel burned)
Sluice Water	0.19 mg total organics/liter of water ^a
Coal	620 ^b
PPTR Ash	0.311 ^c
SASS Sample:	
1 μ m cyclone	<0.0068
10 & 3 μ m cyclone	0.055
XAD-2 resin	1.60
Organic condensate	<0.0027
Total for SASS only	1.66

^a No information is available concerning the amount of sluice water that flows per million Btu (or per Joule) of fuel burned.

^b (17.55 mg/g -- from Appendix H, Table GH-10) (454 g/pound) (82 pounds/MBtu) (9.48×10^{-10} MBtu/J) = 0.00062 mg/J.

^c (0.07 mg/g -- from Appendix H, Table GH-10) (454 g/pound) (82 pounds coal/MBtu) (9.48×10^{-10} MBtu/J) (0.126 pounds ash/pound coal -- from Appendix B) = 3.1×10^7 mg/J.

^d Obtained after multiplying (mg)/(this test) from Table GH-10 in Appendix H by 1.35×10^{-8} ($1/1.35 \times 10^{-8}$ is the number of Joules of fuel that had to be burned to produce the amount of flue gas sampled during this test. See Example No. 2 in Appendix D.)

Organic analysis (summarized in Table C-IV-7) included chromatographic separation (7 cuts) and compound characterization. Low levels (mg quantities) of extractable organics were isolated from the nominal 30 m³ of flue gas sampled. Of the 129 mg of extractable organics, most (>90%) was found in the XAD-2 resin. The complete organic analysis was performed only on the XAD-2, since there were not enough extractable organics in the other components of the SASS train. The GC data together with Fourier Transform Infrared (FTIR) analysis and Mass Spectrometry (MS) indicate the presence of esters, but some of these materials were also found in the blank and should therefore not be heavily considered (See Appendix H). Also found was methyl hexadecanoate. Some glycol ethers may also be present. Dimethyl sulfate (DMS), many silicon-containing materials and methyl esters of aliphatic acids were also detected. However the dimethyl sulfate (a suspected carcinogen, found on one of the XAD-2 extracts) may have been generated as an artifact of the sampling and analysis scheme, and since the SASS is not suitable to sample for dimethyl sulfate it is unknown if this compound was emitted. Details for each of the 7 separation cuts may be found in Appendix H.

For every million Btu (82 pounds) of coal burned, the fuel contains about 1.4 pounds of total extractable organic material or 620 ng/Joule (Table C-IV-7). Other samples contain organics as shown in Table C-IV-7.

C. Coal, Fly Ash, Sluice Water

As indicated on Table C-IV-8, coal, fly ash from the precipitator hopper, and sluice water were each analyzed physically, chemically, and biologically by several specialized outside laboratories. Key findings may be found in Appendixes B, H, and I, and are summarized on the next few pages.

TABLE C-IV-8			
SAMPLE ANALYSIS DONE BY SPECIALIZED LABORATORIES			
Sample Type of Analysis	Coal	Fly Ash	Sluice Water
Physical Analysis: Heat Content Ash Fusion Temp. Ash Elements	Exxon, Baytown (ER&E)		Not Done
Chemical Analysis	Exxon, Linden (ER&E)		
Bio-Assay using aquatic plants and animals	Research Triangle Institute (RTI)		
Bio-Assay using non-aquatic plants and animals	Battelle, Columbus Laboratories (BCL)		

1. Chemical and Physical Analysis

Particulate matter sampled during this test was examined by microscope and revealed a bimodal size distribution with the larger particles averaging about 20 μm and the smaller ones averaging about 3-4 μm . The shape of the ESP fly ash (sampled from the ESP hoppers) had a greater departure from sphericity than did the particulate catch from the ESP inlet (from the SASS train). The ESP ash particles contained mostly silicates. Si, Al, K, and Fe were the most abundant elements in the particles.

Both sluice water effluent and make-up water contained chloride and sulfate. (These anions were also found in the coal and ash extract.)

The coal extract was separated into 7 fractions, but the spectra of each fraction was generally too complex to be analyzed by EPA Level 1 procedures. Instead, a list of the major peaks is presented in Appendix H and shows that the extract was highly aromatic, highly oxygenated material containing phenolics, and carboxylic acids.

2. Biological Analysis

The biological assays were performed to complement the physical and chemical data obtained during the Level 1 environmental assessment. Because most carcinogens also act as mutagens⁽²⁾ the Ames test (on salmonella bacteria) for mutagenic effects was used to screen samples for carcinogenic materials. Results indicate that the coal, electrostatic precipitator (ESP) ash and sluice water are not mutagenic.

Because the lungs are the first defense against toxins on inhalable particles, the rat alveolar (lung) macrophage (RAM) test), was used to evaluate this effect. In this test, cultures of rat lung cells were tested for a toxic response to the samples collected. The RAM assay was negative.

The Chinese Hamster Ovary (CHO) Cell Assay is a test for clonal toxicity in which the ability of a clonal cell colony to live and grow, is measured, after being exposed to the material under study. The CHO test yielded toxic responses with coal leachates and with sluice water. (The ESP ash was not subjected to this assay.)

Whole animal toxicity studies (on live rats) were used to evaluate short-term toxic effects. In these "Oral-Rodent" studies the death rate of the animals after ingesting the prepared samples was less than the toxic response to common table salt.

In the fresh-water aquatic tests involving fish (minnow), daphnia, and algae, respectively, only the coal and ash leachates showed toxic responses. The sluice water was not toxic to these aquatic species but promoted the growth of algae.

The "moderate" to "high" toxicity of the ESP ash leachate on the test species of minnow and daphnia may have been partially due to the increased hardness of the water and increased pH as the leachate was added. At low concentrations, this leachate stimulated the growth of algae.

The biological data for this boiler are summarized in Table C-IV-9.

D. Plume Opacity

During the Level 1 test, one spot check of plume opacity was made by an EPA-certified* "smoke-reader."

The observer read the plume opacity as 60% during the spot check, while the plant's transmissometer indicated 33.1%. (At this plant, it was unusual for the results of the two measurement methods to disagree by this much.) Transmissometer opacity readings are included with the list of operating parameters appended. Typically, at this boiler, the observers opacity readings have been much lower than those of the plants transmissometer. (This occasion was an exception.)

V. DISCUSSION OF LEVEL 1 ENVIRONMENTAL ASSESSMENT RESULTS

At the precipitator inlet, most organics found were on the XAD-2 resin designed to collect organics from the vapor phase. The next largest amount of organic matter was found on the larger particles trapped in the 10 and 3 μ m cyclones. A still smaller amount was found on the particles in the 1 μ m size range. But this may simply be due to the fact that the total mass of the large particles was so much greater than that of the small ones. (70% of the fly ash particle mass was of the 10 μ m size range.)

*In order to be certified, the observer must "read," consecutively, 25 samples of black smoke, and 25 of white smoke. In each category, the samples are in random order from 0 to 100% opaque. No reading may be in error by more than 15 percentage points, and the average error in the black as well as the white category must each be less than 7.5 percentage points. The reference is a calibrated in-stack transmissometer.

TABLE C-IV-9
BIO-ASSAY RESULTS (SUMMARY)

	Bottom Ash/Water Slurry	Precipitator (ESP) Hopper Ash	Coal
Ames Mutagenicity (Salmonella/Microsomal Mutagenesis Assay)	U	U	U
Rat Alveolar (Lung) Macrophage Cytotoxicity Assay (RAM)	-	U	U
Rodent Cell Clonal Toxicity Assay (Chinese Hamster Ovary - "CHO")	M	-	M
In Vivo Oral Rodent (Whole Animal Acute Toxicity - Rat)	U	U	U
Fresh-Water Fish (Fathead Minnow)	U	M	U
Fresh-Water Daphnia Magna (Water Flea)	U	H	U
Fresh Water Algae	U	H	H

KEY

H = High toxicity
M = Moderate toxicity
L = Low toxicity
U = Undetected
- = Not tested

Details may be
found in Appendix I

On a "per mass" basis, the distribution of organics among the particles at the precipitator inlet looks quite different. For the 10 and 3 μm cyclones, only 17 μg were present for every gram of particles ($= 4.1 / (177 + 67)$). But for the 1 μm particles, the amount of organics may have been as high as $(<0.5/8.797) = <700 \mu\text{g/g}$. (This is an upper limit and reflects some amount of uncertainty.)

This indicates that of the organics that condensed on fly ash at the sampling temperature (400°F), such condensation favored formation on small particles (those with the largest surface area per mass) and may have been limited only by the number of small particles available. (The SASS test performed on the inlet of the precipitator, showed a size distribution favoring large particles.) Since condensation is a surface effect, the smallest particles (which have the highest surface area to volume ratio) are most likely to be coated. In addition to organics, metals were also analyzed. For the precipitator inlet sample, the metals seemed to favor the small particles, but the amounts of EPA-designated toxic metals were near or below detection limits.

The EPA's Industrial Environmental Research Laboratory/RTP, in 1977, developed an approach to assist in performing cost effective characterizations of control technology and source discharge emissions. This approach involves the concept of trigger values, and Discharge Multimedia Environmental Goals (DMEGs). When applied to preliminary characterization data, this approach can be used to rank individual chemicals and discharge streams in terms of their relative potential for environmental impact and thus suggest which species and streams warrant further analysis. The trigger values (DMEGs) were calculated using simplified models based upon health and ecological information available at that time. Thus, it should be made clear that the DMEGs are not applicable to risk assessment. They are only an engineering tool aimed at suggesting, in an organized fashion, which waste streams and potential pollutants warrant further investigation.

Table C-V-1 lists the gas-phase source emissions for thirteen of the elements analyzed in this study and compares their respective concentrations with the 1977 DMEG values (formerly called MATE - Minimum Acute Toxicity Effluent - values). Of the reliable data, only cadmium, copper, chromium, nickel and zinc have gaseous media source emission rates in excess of their DMEG values. But, the chromium and nickel detected probably came from the stainless steel components of the sampling system. Similarly, copper and zinc are commonly found in piping and galvanized metal coatings around a power plant. Thus, these metals may not represent products of combustion, and as such, should not necessarily be a cause of concern. Other metals, because of their high concentration in the particulate phase, may have originated in the coal. The coal, however, was not analyzed for these metals.

DMEG values for other pollutants may be found in references 3 through 7 for comparison with emission rates reported herein. Similarly, reference 8 presents information on typical emissions.

TABLE C-V-1

EMISSIONS OF 13 EPA PRIORITY
(FOR WASTEWATER) POLLUTANT METALS

(COMPARISON WITH LIMITING DMEG VALUES FOR GASEOUS SOURCES)

Element	Source Emission Rate (Gaseous Media Only)		Discharge Stream Multimedia Environmental Goals (DMEGs) For Source Emissions in Gaseous Media	
	mg/MBtu	$\mu\text{g}/\text{m}^3$ *	Based on Health Effects ($\mu\text{g}/\text{m}^3$)	Based on Ecological Effects ($\mu\text{g}/\text{m}^3$)
Ag	<16	<58	10	
As	300 ^b	1079 ^b	2	
Be	(12)	(43) ^b	2	
Cd	210 ^b	755	10	
Cr	820	2950	1	
Cu	440	1583	200	
Hg	1.3	5	50	10
Ni	1100	3957	15	
Pb	(200) ^b	(719) ^b	150	
Sb	(260) ^b	(935) ^b	500	
Se	<97 ^b	<349	200	
Tl	(90) ^b	(324) ^b	100	
Zn	3300	11900	4000	

a Data less reliable due to significant spectral or background interferences.

b Data unreliable due to strong interferences or weak signals.

() Means that the value is less than 3 times the ICPEs detection limit or the blank value. These results may not be significant since they are more easily affected by background fluctuations.

< Means that the printed value represents the lower limit of detection for the element in that particular sample.

* Assumes 9820 ft³ (278 m³) of flue gas per MBtu. These values are "worst-case" emissions since 9820 ft³/MBtu (278.1 m³/MBtu) is the value for undiluted dry flue gas.

VI. REFERENCES (FOR PART C)

1. IERL-RTP Procedures Manual: Level 1 Environmental Assessment (Second Edition). EPA-600/7-78-201. NTIS No. PB 293795. October, 1978. Pgs. 55 and 56.
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PART D
CORROSION PROBE TESTS

I. BACKGROUND

LG&E's Mill Creek Boiler No. 3 was designed to meet the New Source Performance Standard (NSPS) for NO_x emissions applicable at the time of construction (0.7 lb/MBtu, or 301 ng/J). Under this program, the effect of "Low-NO_x" operation on water wall corrosion rate was evaluated.

A. Purpose for Corrosion Testing

One method of decreasing NO_x emissions for compliance with NSPS regulations, is to decrease the amount of excess air in the burner zone. However, an oxygen deficient flame can be corrosive, especially in the presence of high sulfur concentrations. From a corrosion point of view, a furnace wall coated with high-sulfur slag while exposed to a chemically reducing (oxygen deficient) atmosphere is an undesirable situation which could lead to increased corrosion.

B. Previous Related Work Performed by Exxon

Since 1969, Exxon⁽¹⁾ and others⁽²⁾ have identified sources of NO_x emissions and evaluated methods for decreasing those emissions. The reports identified utility boilers as a major NO_x source which, in short term tests, respond well to NO_x controls. Approximately forty boilers were tested. The tests focused mostly on flue gas emissions, slagging, and decreased operational flexibility as possible side effects of "low-NO_x" operation. Relatively little work was performed on the possible corrosive results of low-NO_x operation. The few corrosion studies that were performed were of short duration (30 to 1000 hours). Long term studies on slagging and corrosion were needed.

C. Previous Corrosion Probe Testing by Exxon

Corrosion testing by use of corrosion probes is an art still under development. The present program uses probes of a third generation design. Each of the first generation corrosion probes used by ER&E consisted of a flat square plate a few inches on a side and about 1/8 inch thick mounted on a probe holder a few feet long which supplied cooling air to the back of the plate. The assembly was inserted into the furnace through an inspection door and the front of the plate was exposed to the furnace gases. This probe design was notorious for allowing the supply of cooling air to leak into the furnace thus sheathing the plate in a capsule of clean air and preventing it from being exposed to the corrosive furnace gases. Furthermore, the cooling effect of the air was not uniform and

caused large temperature gradients over the small plate. This corrosion probe design was quickly abandoned in favor of the second generation of corrosion probes.

In the second generation of corrosion probes the corrosion coupons (of which three of various materials were typically mounted on each probe), were fabricated from actual boiler wall tube materials. The assembly of 3 cylindrical coupons, screwed end to end, formed a cylinder about 6 inches long and 1 1/2 inches in diameter. It was inserted horizontally a few inches into the boiler through an inspection door and was cooled by air circulated inside the cylindrical assembly.

The first use of these probes involved high temperature accelerated corrosion testing of acid "pickled" coupons. But correlation between probe corrosion rates and actual wall corrosion rates was poor, so the practice of pickling was stopped. High temperature testing was also stopped, and in subsequent tests, the coupons were cooled to the same temperature as the boiler walls.

Corrosion rates were determined by weight loss analysis after slag was removed in an ultrasonic bath containing microscopic glass beads. ("Control" specimens were also included in the bath.) However, some investigators felt that the horizontal orientation of the probes caused unnatural slag formations on the probes leading to extraordinary corrosion, therefore, the third generation of probe coupons (designed by Combustion Engineering, Inc.) were mounted vertically in the boiler and simulate as closely as possible, pieces of boiler wall-tube. This probe design was used for the tests described in this report.

D. Other Methods for Determining Corrosion Rate

Corrosion testing by probes was only one of three methods used to determine boiler wall corrosion rates under this program. The three methods were:

- o Ultrasonic Thickness (UT) Mapping (of the furnace walls)
- o Corrosion Panels (installing pre-characterized sections of the furnace walls for analysis)
- o Corrosion Probes (pieces of boiler wall tube inserted into the furnace through inspection doors with corrosion rate determined by weight loss analysis)

In addition, furnace gas was sampled from 40 locations along the walls of the furnace to identify locally corrosive environments for correlation with actual corrosion measurements.

II. EXPERIMENTAL PROCEDURES

A. Probe Design

The corrosion probes (shown in Figure D-II-1) and control systems were designed and built by Combustion Engineering, Incorporated (CE). The geometry was such that each probe could be inserted into the furnace through a standard 4" X 10" CE inspection door. (Four such doors were installed for this study.) Each probe contained 5 corrosion coupons (also called "test rings") of various materials including one surface-coated test ring of either Metco coating 444 or Hastelloy C-276. Three thermocouples were provided for temperature measurement and control. The probes were air cooled to keep the center coupon at 650°F.

For each of the four probes, a continuous log of the middle coupon temperature was kept on a strip-chart recorder-controller which was also used to control the cooling air. The high temperature alarm system also operated on the signal from the middle coupon. A data logger recorded all three thermocouple outputs from each of the 4 probes at least once per hour.

Three tests using corrosion probes were performed. Each test involved exposing 4 probes (each containing 5 coupons) to the furnace gases for a known time period. For the first test, the exposure period was 30 hours. The second used a 300 hour exposure, and the third lasted 1000 hours. During the tests, the boiler was operated according to its normal load pattern.

B. Probe Locations

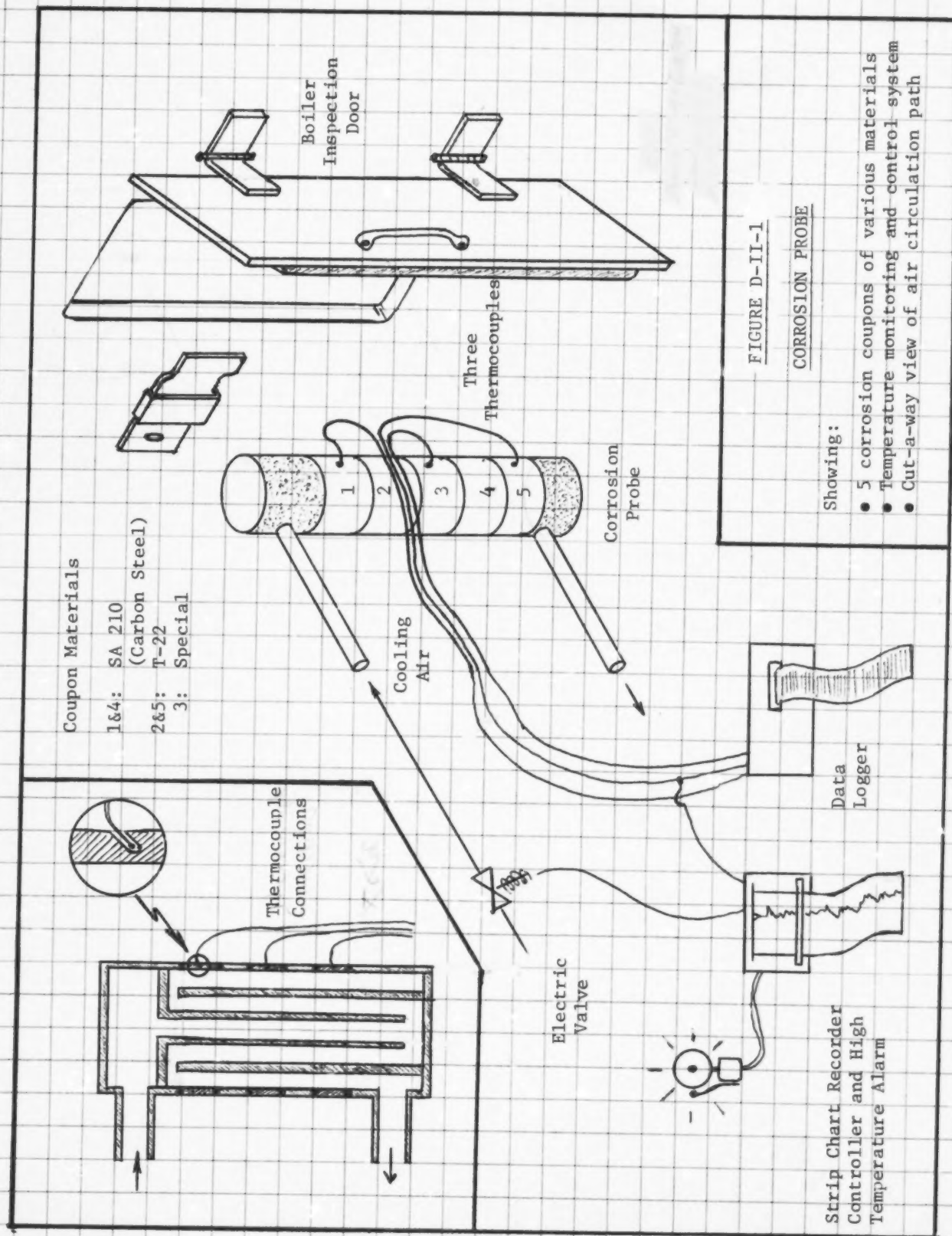
Each of the four corrosion probes was inserted into the boiler through an inspection door specially installed for the test. For identification, each corrosion probe door was assigned a number (1 through 4). The identification and location of the corrosion probe doors are indicated on Figure B-II-4, and Table D-II-1.

C. Analytical Procedure

Coupon corrosion rate was determined by weight loss analysis as well as by micrometer measurement of coupon wall thickness after carefully removing slag deposits by scrubbing and brushing with a mild acid solution.

For each coupon, to convert the weight loss data to a thickness change, first the weight loss (grams) for each coupon was divided by the exposed surface area* of the coupon (cm^2) to give the weight

*For each coupon, half of its outside surface is exposed to the radiant heat and slag in the furnace. The other half sees the furnace wall. Hence for each coupon, the exposed area is equal to half of the total visible outside surface area.



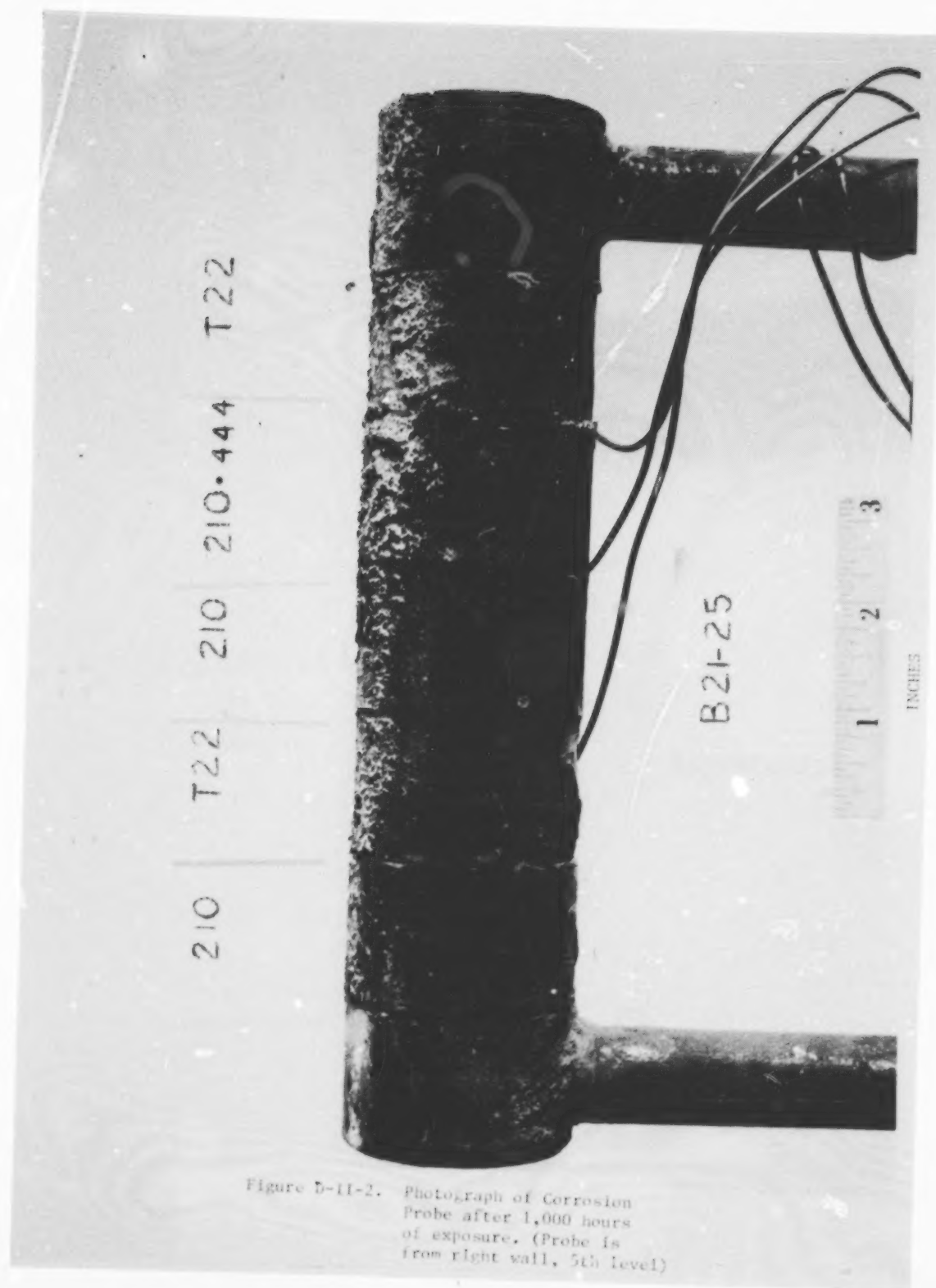


Figure D-11-2. Photograph of Corrosion Probe after 1,000 hours of exposure. (Probe is from right wall, 5th level)

TABLE D-II-1

CORROSION PROBE IDENTIFICATION

PROBE ID NUMBER	LOCATION OF PROBE DURING EXPOSURE PERIOD (ELEVATOR FLOOR NUMBER)	ID NUMBER OF CLOSEST PANEL	FIRST TEST (30 HOUR EXPOSURE)	SECOND TEST (300 HOUR EXPOSURE)	THIRD TEST (1000 HOUR (1000 HOUR EXPOSURE)
(SEE FIGURE B-II-4)				COUPON ID Nos.	
1	3rd Floor Left (North)	4	A26 to A30	C21 to C25	C26 to C30
2	3rd Floor Right (South)	5	B11 to B15	C1 to C5	B26 to B30
3	5th Floor Right (South)	6	B6 to B10	C16 to C20	B21 to B25
4	6th Floor Rear (East)	7	B1 to B5	C11 to C15	B16 to B20

loss per exposed surface area (g/cm^2). This number was then divided by the density of the coupon material ($7.83 \text{ g}/\text{cm}^3$) to give the average thickness change (in centimeters) for the exposed surface. This was then converted to units of inches or mils.* Dividing this number by the exposure time gives the average corrosion rate for the period (inches (or mils) per year).

III. RESULTS AND DISCUSSION OF CORROSION PROBE TESTS

The data generated by these probes indicate that:

- o Losses for both carbon steel (SA-210) and T-22 material were not significantly different from each other.
- o No correlation was found between corrosion rate and location within the furnace.

Probe locations, exposure times and coupon identifications are shown in Figure B-II-4 and Table D-II-1 which show, for example, that during the 30-hour test, probe No. 1 (containing test rings A-26 through A-30) was exposed on the front wall and at the highest elevation. Table D-III-1 summarizes the results of these corrosion probe test performed at LG&E. Figure D-III-1 is a graphic summary of those results.

The weight loss method of calculating metal wastage provides an average for the entire portion of the coupon's surface that sees the radiant heat of the furnace. However, on each coupon, some spots may have corroded more than others (pitting) as was revealed by the many micrometer measurements on each coupon of each probe, the maximum loss (as measured by micrometer) for each material is shown on Table D-III-1. On the average, the weight loss analysis showed a higher total loss (in mils) for the longer exposure tests than for the shorter tests. However, these results were not strongly supported by the micrometer measurements (probably because the values were very near the lower limit of resolution for the micrometer). Prior to the start of the test, some of the coupons were coated with a material thought to inhibit corrosion. The tests showed no advantage in such a coating unless perhaps a better bond can be established between the base-metal and its surface coating. Beyond this, the coated coupons were not considered in the overall data analysis.

Although the total loss (mils) increases with increasing exposure time, Figure D-III-1 shows that as time passes, the rate of loss (mils per year) decreases. This seems to indicate that elements within the corrosive atmosphere of the furnace, deposit on the tube surface thus conditioning the tube and forming a coating which may inhibit further corrosion. (This may be similar to the non-porous oxide coating that forms on freshly cut aluminum to coat and protect the underlying surface

*1 mil = 0.001 inch.

TABLE D-III-1

SUMMARY OF METAL LOSS DATA FOR
UNCOATED CORROSION PROBE COUPONS*

EXPOSURE TIME	PROBE ID	THICKNESS LOSS					
		Calculated Value (by Weight-Loss Method)				Maximum Actually Measured Value (by Micrometer)	
		SA-210 (MILS)	T-22 (MILS)	SA-210 and T-22 (MILS) (MILS) YEAR		SA-210 (MILS)	T-22 (MILS)
30 hours	1	0.17	0.12	0.14	41	1	1
	2	0.93	0.53	0.73	213	1	1
	3	0.13	0.09	0.11	32	1	1
	4	0.10	0.12	0.11	32	1	1
	AVG.	0.33	0.22	0.27	80		
300 hours	1	0.42	0.28	0.35	10.2	1	2
	2	0.22	0.44	0.33	9.6	2	2
	3	1.63	0.19	0.91	26.6	3	1
	4	0.19	0.23	0.21	6.1	1	1
	AVG.	0.62	0.29	0.45	13.1		
1,000 hours	1	1.27	1.32	1.30	11.2	1	2
	2	2.18	1.15	1.66	14.6	3	1
	3	0.20	0.36	0.28	2.41	1	1
	4	0.54	0.52	0.53	4.57	1	1
	AVG.	1.05	0.84	0.94	8.2		

*Each probe contained five coupons:

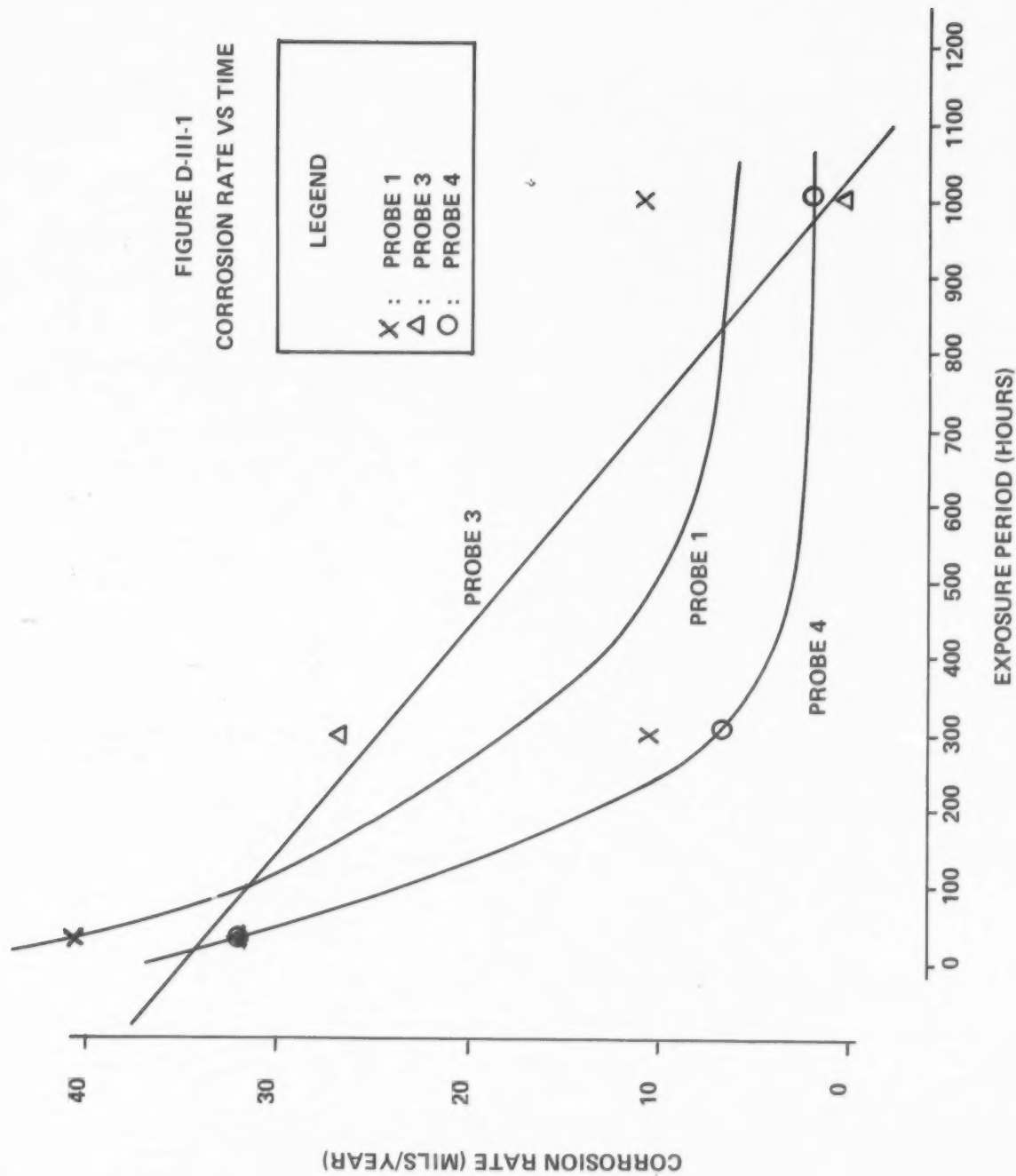
One Coated

Two uncoated of steel type SA-210

Two uncoated of steel type T-22

For each probe, the average loss for the two uncoated SA-210 coupons was calculated, and so was the average loss for the uncoated T-22 material. These averages are reported here.

FIGURE D-III-1
CORROSION RATE VS TIME



from further oxidation.) The graphs on Figure D-III-1 show that for the longer exposure tests, the corrosion rate approaches that normally expected for boiler walls (less than about 3 mils per year).

IV. REFERENCES (For Part D)

- (1) W. Bartok, A. R. Crawford, A. R. Cunningham, H. J. Hall, E. H. Manng, A. Skopp. "Systems Study of Nitrogen Oxide Control Methods For Stationary Sources" - Volume II. Prepared by Esso (now Exxon) Research and Engineering Company, Linden, NJ for the National Air Pollution Control Administration (NAPCA, now EPA). NTIS No. PB-192 789, November, 1969.
- (2) Proceedings: Second NO_x Control Technology Seminar (prepared by the Electric Power Research Institute-EPRI). Section 1: "Utility Boiler NO_x Emission Characterization" by H. B. Mason, K. G. Salveson, A. B. Shimizu, and N. Concion of Acurex Corporation. EPRI and NTIS No. EPRI FP-1109-SR. July, 1979.

PART E

ULTRA SONIC DETERMINATION OF CORROSION RATES

(Wall measurements and corrosion panel tests)

I. BACKGROUND

The most reliable method of determining the corrosion rate of a boiler's water-wall tubes is by measuring the tube wall thickness before and after a well defined operating period. At Mill Creek No. 3, wall thickness measurement was accomplished ultrasonically by echoing sound waves through the tube walls. The echo time delay was used to determine the wall thickness of each tube measured.

This nondestructive test was performed at thousands of wall locations inside the furnace. The result was a map of wall thickness within the boiler. Another corrosion study method involved cutting out old sections of the boiler wall and installing new sections called "corrosion panels," for study.

Both methods required entry into the boiler, which could be done only during an outage. Special equipment was required to reach the test locations. These methods although considerably more difficult than either the furnace gas tap or corrosion probe methods used in this program, yielded results which were more confidently related to true corrosion rate.

II. EXPERIMENTAL PROCEDURE

The original wall thickness measurements occurred during the December, 1979 outage and included hundreds of points on all four walls at six elevations inside the furnace. (The measurement elevations are shown in Figure B-II-4. Also during this outage, seven sections (each five tubes wide (about 1 foot wide) and 10 feet tall) of the original boiler walls were cut out and replaced with new sections which had been carefully prepared and measured. These new sections, called corrosion panels, consisted of five tubes, alternately of the usual wall tube material (SA-210 grade A1 CF for the hopper, and SA-213 grade T2 CF for the bulk of the furnace) and a material thought to have increased corrosion resistance (SA-213 grade T2 CF for the hopper, and SA-213 grade T-11 CF for the bulk of the furnace). Next to four of the seven panels, doors were installed to allow corrosion probes to be inserted into the furnace near the corrosion panels.

In March of 1982, about two years (15,000 hours of on-line operation) after the initial measurements, the corrosion panels and other parts of the walls were remeasured to determine tube wastage rate.

With the exception of a few measurements made by micrometer on the ends of cut tubes, most thickness measurements were performed ultrasonically. The ultrasonic method measures the time required for a sound echo to bounce off the tube's inner surface, and requires careful preparation of the tube's outer surface so that the sound transmitter/receiver may be acoustically coupled to it.

Tube surface preparation involved cleaning by motorized wire brush to remove deposits until the white metal of the tube's true outer surface was revealed. Special care was taken to insure that all surface coatings were removed, without removing any of the tube material itself.

Additionally, the test plan was designed to factor out any bias or change in the corrosion rate that might result from the cleaning procedure. (Some researchers feel that a freshly cleaned surface will corrode faster than an older surface.) This part of the plan was designed to allow for the optional continuation of the test even after its scheduled conclusion.

Other steps taken to insure the quality of the data included frequent calibrations, and repeatability tests.

Panel and measurements locations were most heavily concentrated in areas where corrosion was most expected such as at burner elevations, and near the corners of the side-walls (where the flame comes closest to the walls).

For improved mixing and heat transfer, Mill Creek No. 3 uses rifled tubes in the furnace zone. The rifling (only on the inside of the tube) consists of a series of spiral grooves about 1/16 inch deep. So, within a small area, the wall of each tube had a thick part (0.350") and a thin part (0.290"). Generally, only the thin parts were measured. (Some of the exceptions are noted in Appendix J.)

III. RESULTS

During the final thickness measurements, it became apparent that the measurements were being affected by random errors. One proof of this was the occasional measurement of a thickness gain. By averaging many data points, random errors were averaged out. In order for the average to be valid, it must include all data points including those that show negative corrosion. In the average, these negative random errors will neutralize the positive random errors (which are not as easily recognized) and thus, the average value will be true. Alternatively, if all the values containing negative errors had been discarded, then the average would include only the hidden positive errors (of unknown value) and results would be heavily biased in that direction. Hence, the negative values have been saved and included on the data tables that follow.

Two major sources of random error relate to:

- o Locating the trough (thinnest part) of the cycle in the rifled boiler tubes.
- o Locating and remeasuring the same points that were measured during the first visit.

Both of these error sources relate to finding (within fractions of an inch on a 100 foot wall) and measuring the same points on two different occasions nearly two years apart. Because the rifling cycle repeats about three times per inch (see drawing in Appendix J), accurate measurements of thickness changes can be made only if the measurement locations are known within a fraction of an inch. On a 50 x 150 foot boiler wall, this is not an easy task and will introduce some random errors in the corrosion measurements. However, by measuring many points and averaging the results, the random errors can be minimized.

A. Panel Measurements

The initial panel measurements were made before the panels were installed in the boiler circuit and included thickness measurements on both the hot and cold sides as well as "on-crown" and "off-crown" eccentricity measurements and measurements on both the thick and thin parts of the tube-wall rifling. However, because of cost and time constraints, many of these measurements were not repeated during the second measurements period.

Figure E-III-1 shows panel geometry and measurement locations for the data reported. Measurement results are summarized in Table E-III-1, and represent the effects of about two years of exposure to the furnace environment (15,000 hours of on-line operation between December 1979 and March 1982).

Note that on the average, the panels lost 2.3 mils during the two year exposure period. Dividing by the "on-line" time (15,000 hours) gives a corrosion rate of 1.34 mils per year.

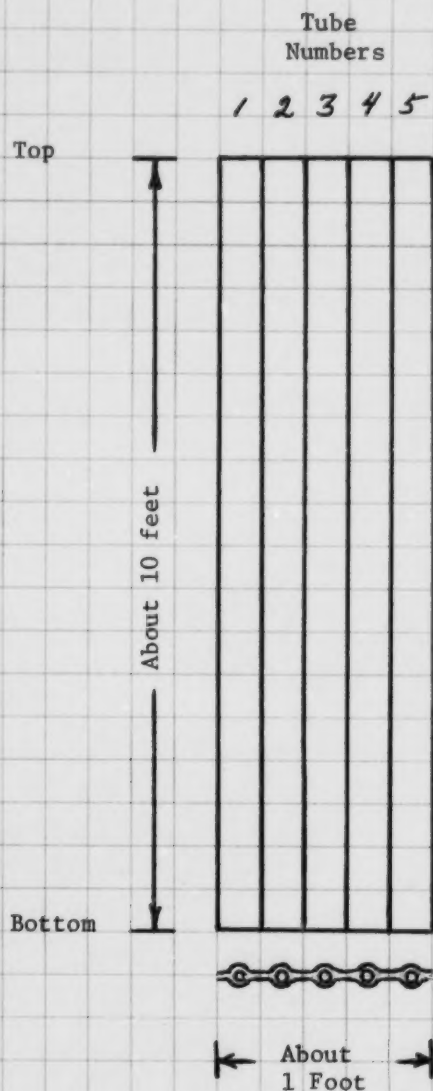
B. Other UT Wall Thickness Results

In addition to the panel measurements, thousands of other points along the walls were measured in order to produce a map of metal loss throughout the furnace.

Table E-III-2 presents a summary of this metal loss data.

FIGURE E-III-1

CORROSION PANEL GEOMETRY (ALL TUBES ARE RIFLED)



View as Seen from Inside
The furnace (Fireside View)

Tube Materials*		
	Hopper Panels (Nos. 1&2)	Furnace Panels (Nos. 5-7)
Even Numbered Tubes	SA 213 0.265" T2 CF	SA 213 0.240" T2 CF
Odd Numbered Tubes	SA 210 0.265" A1 CF	SA 213 0.240" T11 CF

Generally, the thickness of each tube was measured every foot or two along its length.

* Steel Type, Nominal Wall Thickness, Grade

TABLE E-III-1

AVERAGE TUBE-WALL LOSS* FOR PANELS (MILS)
 ("ON-LINE" EXPOSURE TIME = 15,000 HOURS)

PANEL ID NUMBER	PANEL LOCATION	TUBE NUMBER					AVERAGE	
		1	2	3	4	5	(MILS)	(MILS/YEAR)
1	Front wall on Hopper Slope	-4.2	-7.2	-0.7	+2.6	+1.3	-1.6	
2	Rear wall on Hopper Slope	+3.8	-0.2	-6.8	+3.3	+3.9	+0.8	
3	Rear wall at Top Burners	+3.2	+2.2	+2.4	+1.6	+3.6	+2.6	
4	Left wall at Top Burner Elevation	-4.1	+2.2	+3.5	+0.1	+3.4	+1.0	
5	Right wall at Top Burner Elevation	+4.0	+5.8	+4.5	+9.4	+1.7	+5.1	
6	Right wall, just above top burner elevation	+3.5	+5.7	+3.7	+9.2	+0.3	+4.5	
7	Rear Wall, well above burners	+4.4	+3.9	+4.2	+3.5	+2.8	+3.6	
AVERAGE							+2.3	+1.34

*Positive numbers indicate a loss. Negative values indicate that the sample may not have been large enough to average out random errors. See text.

IV. DISCUSSION AND SUMMARY OF CORROSION RESULTS

Corrosion rate was measured by three methods:

- o Corrosion probes
- o Corrosion panels
- o Wall thickness mapping

For the corrosion probes (Table D-III-1 and Figure D-III-1) the rate of metal loss seemed to decrease (from more than 30 mils/yr to less than 10 mils/yr) as the exposure time increased. This indicates that, had the program continued (to include longer exposure times), the corrosion rates for the probes would continue to approach the expected (and actually measured) long term loss rate for the furnace walls.

The corrosion panels (Table E-III-1) had an average loss rate of 1.34 mils per year compared with the average wall loss rate (Table E-III-2) of 2.3 mils per year. No correlation was found (in any of the methods) between corrosion rate and location in the furnace. Tubes close to the burners did not corrode measurably more than those farther from the flame. Furthermore, of the steel types tested, there seemed to be no advantage of any one from a corrosion point of view.

The rate of corrosion within this boiler was such that, on the average, it would require more than 30 years for the tubes to lose half their thickness. However, the large scatter in the data indicate that some tubes may corrode significantly faster than the average, and these tubes may be the ones that limit boiler life.

TABLE E-III-2

SUMMARY OF METAL LOSS DATA FOR FURNACE WALLS
 ("ON-LINE" EXPOSURE TIME BETWEEN MEASUREMENTS = 15,000 HOURS)

Elevation	Thickness Loss (MILS)				Average	
	Left wall	Right wall	Front wall	Rear wall		
					(mils)	(mils/year)
F (Near Nose)	+5.0	+3.1	+4.3	+3.7	+4.0	+2.3
E	+3.1	+2.5	+5.2	+3.0	+3.4	+2.0
D	+2.0	+3.1	+6.5	+5.9	+4.4	+2.6
C	+4.4	+6.7	+3.6	+1.1	+3.7	+2.2
B	+1.6	+5.0	+5.4	+2.1	+3.5	+2.0
A (In Hopper)	+6.3	-1.7*	+10.1	+1.1	+4.8	+2.8
AVERAGE	+3.7	+3.1	+5.9	+2.7	+3.9	+2.3

*Negative values indicate a measured thickness gain. As explained in the text, this may be due to random errors in a data sample that was too small to average them out. By including them in the grand averages, they help to neutralize other (hidden) random errors.

PART F
THIRTY-DAY CONTINUOUS
MONITORING OF FLUE-GAS EMISSIONS

(This part of the report summarizes work performed by KVB Inc., a sub-contractor to Exxon for this task.)

I. PURPOSE OF THE THIRTY-DAY TESTS

The thirty-day tests were performed with two goals in mind:

- o To quantify flue gas emissions during normal load patterns over a period long enough to be representative of long-term operation.
- o To evaluate the ability of continuous monitors to perform within the EPA's performance specifications for such monitors.

To these ends a continuous record of 15-minute emission averages (CO, CO₂, O₂, and NO_x) was logged concurrently with boiler operating data over each of the 30-day periods. Also, the continuous emission monitors (CEM) were checked for quality and for compliance with EPA performance specifications PS-2 (for SO₂ and NO_x monitors) and PS-3 (for CO₂ and O₂ monitors). This evaluation included several measurements of drift, accuracy, precision (repeatability), and response time.

II. EXPERIMENTAL PROCEDURES FOR THE 30-DAY TESTS

Two 30-day tests were performed on the Mill Creek boiler (January to February 1981, and February to April 1981). During each test, boiler load was recorded along with a semi-continuous (once every four seconds) record of stack emissions. Also, at periodic intervals, the performance (zero and span drift, response time, accuracy, etc.) of each continuous emission monitor was evaluated according to EPA procedures to ensure good performance and quality data. The sampling and analysis methods were similar to those described in Part B, Section II of this report. A more detailed description of the experimental procedures used for the 30-day tests may be found in Appendix G.

III. RESULTS AND DISCUSSION OF THE 30-DAY TESTS

A. Continuous Monitor Certification Tests

During the two 30-day test periods, the continuous monitor system was used to measure the boiler's gaseous emissions. Following shipment to the test site, the monitoring system was installed and certification tests were performed according to EPA's Performance Specification 2 (PS2) and 3 (PS3), 40 CFR 60. These specifications

establish minimum performance criteria that the monitoring system must meet in terms of eight parameters: accuracy, calibration error, two- and 24-hour zero drifts, two- and 24-hour calibration drifts, response time, and operational period.

For the first test, the continuous monitor system was installed and instruments were initially calibrated on January 16, 1981. For the second test, the corresponding date was February 25, 1981. The second test, however, was interrupted on several occasions; twice (February 28, and March 1) during the certification test due to plant shut-downs for maintenance, and from March 5 to March 26 because of a labor strike at the plant. The test was restarted on March 23, and was concluded on April 24, 1981.

The raw data for the CEM performance certification tests are too voluminous for presentation here. However, those data, and the performance of the continuous monitor system are summarized in Table F-III-1. All performance values are in percentage of the span value. Also shown in the table are the monitor specifications extracted from PS2 and PS3. The performance of the CO analyzer, which is not covered by a formal performance specification, is also included on the table. KVB requires the CO monitor to meet the same specifications as the NO_x analyzer. (The CO analyzer is used to monitor the combustion conditions in the boiler since it is a very sensitive indicator of combustion performance.) Table F-III-1 shows that each analyzer in the continuous monitor system performed better in all categories (accuracy, drift, etc.) than is required by the EPA performance specifications.

The results of the relative accuracy determination showed that the NO instrument exceeded the accuracy requirements of PS2. More specifically, during the first 30-day test, the relative accuracy of the Thermo Electron NO analyzer was 18.2 percent based on the initial test results, and 17.5 percent based on the final test series. Similarly, for the second 30-day test, the corresponding relative accuracy numbers were 12.4% and 10.6% based on the initial and final series, respectively. The relative accuracy requirement published in PS2 is ≤ 20 percent of mean reference value. Hence, all the experimental values fall within the requirements of the performance specification, and all of the relative accuracy tests showed that the NO instrument exceeded the accuracy requirements of PS2.

B. Gaseous Emissions Test Results

Summaries of the 24-hour averages for the 30-day test periods are presented in Tables F-III-2 and F-III-3. The tables show that although boiler load varied a great deal, NO emissions were relatively steady during the 30-day tests. A partial listing of the 15-minute averages, from which the 24-hour averages were compiled, may be found at the end of Appendix G.

TABLE F-III-1
INSTRUMENT SPECIFICATIONS AND PERFORMANCE

Parameter	Specifications	Performance	
		1st Test	2nd Test
A. Thermo Electron Series 10 NO _x Analyzer			
Accuracy	< 20% of mean ref. value	17.8%	11.52%
Calibration error mid	< 5% of cal gas value		0.7%
high	< 5% of cal gas value		1.26%
Zero drift (2 hour)	2% of span	0.034%	0.04%
Zero drift (24 hour)	2% of span	0.150%	0.145%
Calibration drift (2 hour)	2% of span	0.085%	0.155%
Calibration drift (24 hour)	2.5% of span	1.280%	0.46%
Response time	15 minute maximum	212 sec	55 sec
Operational period	168 hour minimum	168 hr	168 hr
B. Horiba Instruments PIR 2000 CO ₂ Analyzer			
Zero drift (2 hour)	< 0.4 pct CO ₂	0.1%	0.03%
Zero drift (24 hour)	< 0.5 pct CO ₂	0.0%	0.03%
Calibration drift (2 hour)	< 0.4 pct CO ₂	0.0%	0.13%
Calibration drift (24 hour)	< 0.5 pct CO ₂	0.0%	0.13%
Response time	10 minutes	144 sec	42 sec
Operational period	168 hour minimum	168 hr	168 hr
C. Beckman Instruments Model 742 O ₂ Analyzer			
Zero drift (2 hour)	< 0.4 pct O ₂	DNA*	DNA*
Zero drift (24 hour)	< 0.5 pct O ₂	DNA*	DNA*
Calibration drift (2 hour)	< 0.4 pct O ₂	0.06%	0.03%
Calibration drift (24 hour)	< 0.5 pct O ₂	0.15%	0.25%
Response time	10 minutes	127 sec	49 sec
Operational period	168 hour minimum	168 hr	168 hr
D. Horiba Instruments PIR 2000 CO Analyzer			
Calibration error mid	< 5% of cal gas value		1.02%
high	< 5% of cal gas value		0.69%
Zero drift (2 hour)	2% of span	0.21%	0.032%
Zero drift (24 hour)	2% of span	0.22%	0.391%
Calibration drift (2 hour)	2% of span	0.33%	0.29%
Calibration drift (24 hour)	2.5% of span	0.21%	0.58%
Response time	15 minutes	115 sec	49 sec
Operational period	168 hour minimum	168 hr	168 hr

*Instrument has no zero adjustment.

TABLE F-III-2

SUMMARY OF DAILY AVERAGE EMISSIONS AND OPERATING DATA
MILL CREEK UNIT NO. 3, TEST 1

24-HOUR DATA DRY STACK GAS CONCENTRATION									
Date 1981	Elec Load MW _e	Therm Load MW _{th}	O ₂ Vol%	CO ₂ Vol%	CO ppmv 3% O ₂	NO ppmv 3% O ₂	CO ng/J	NO ng/J (as NO ₂)	NO lb/MBtu (as NO ₂)
1/18	202	363.4	7.8	11.7	0	317	0	186	0.43
1/19	286	507.9	7.5	11.8	0	381	0	224	0.52
1/21*	338	755	4.6	13	1	413	0	242	0.56
1/22	330	624.4	4.8	12.8	5	359	1	210	0.49
1/23	287	533.5	5.3	12.2	0	326	0	191	0.44
1/24	229	408.5	6.6	11.3	0	280	0	164	0.38
1/25	187	338.2	8.6	9.6	0	264	0	155	0.36
1/26	168	309	9.7	8.5	3	310	1	182	0.42
1/27	102	191.3	11.7	6.4	9	333	3	196	0.46
1/28	104	195.6	11.8	6.9	5	346	2	203	0.47
1/29	105	202.8	11	8	0	344	0	202	0.47
1/30	104	212.9	11.2	8.1	0	339	0	199	0.46
1/31	105	200.7	11.7	8	1	351	0	206	0.48
2/1	101	194.6	11	8.2	9	339	3	199	0.46
2/2	310	594.5	6.7	12.8	6	392	2	230	0.53
2/3	383	732.6	5	14.5	0	424	0	248	0.58
2/4	347	664	5.7	13.7	0	393	0	231	0.54
2/5	401	773.4	4.5	14.8	3	394	1	231	0.54
2/6	242	668	5.7	13.8	4	378	1	222	0.52
2/8	134	275.7	9.5	9.4	0	321	0	188	0.44
2/9	287	528.3	5.6	13.3	0	361	0	212	0.49
2/10	300	569.4	5	14.1	2	341	0	200	0.47
2/11	352	659.7	4.9	14.6	0	390	0	229	0.53
2/12	391	748	4.2	15.2	0	396	0	232	0.54
2/13	304	617.7	5.5	14.3	55	366	19	214	0.5
2/14	257	479.9	7.1	12.9	40	364	14	213	0.5
2/15	202	376.5	8.1	11.7	0	359	0	211	0.49
2/16	271	510.1	7.3	12.4	22	372	7	218	0.51
2/17	272	508.3	6.2	13.4	18	348	6	204	0.47
2/18	239	444.6	7.1	12.7	11	344	4	202	0.47
2/19	317	557.9	5.7	13.9	15	355	5	208	0.48
2/20	292	564.6	6.6	12.5	38	365	13	214	0.5

*Jan. 21: Certification tests interrupted due to steam coil repair.

TABLE F-III-3

SUMMARY OF DAILY AVERAGE EMISSIONS AND OPERATING DATA
MILL CREEK UNIT 3, TEST 2

24-HOUR DATA DRY STACK GAS CONCENTRATION*									
Date 1981	Elec Load MW _e	Therm Load MW _{th}	O ₂ Vol%	CO ₂ Vol%	CO ppmv 3% O ₂	NO ppmv 3% O ₂	CO ng/J	NO ng/J (as NO ₂)	NO lb/MBtu (as NO ₂)
2/26	331	571.2	5.3	13	-	341	-	200	0.47
2/27	223	417.9	7.5	10.4	-	354	-	208	0.48
3/2**	316	718.1	4.5	13.4	-	406	3	238	0.55
3/3	323	602.4	4.8	14	28	371	10	217	0.5
3/4	366	694.9	4.2	13.6	33	364	11	214	0.5
3/23***	332	692.6	4.3	12.6	28	382	10	224	0.52
3/24	296	555.9	5.3	13.5	25	352	9	206	0.48
3/25	305	566.4	5.8	11.8	30	359	11	210	0.49
3/26	300	529.1	6.2	11.5	32	395	11	232	0.54
3/27	200	309.9	8.3	9.5	49	367	17	215	0.5
3/30	305	574.8	6	12.2	-	377	-	221	0.51
3/31	323	605.5	5.2	12.6	30	377	11	221	0.51
4/1	327	614.6	5.4	12.2	42	373	15	219	0.51
4/2	325	609.9	5.9	11.7	39	381	14	223	0.52
4/3	188	345.4	8.8	8.8	50	350	17	205	0.48
4/4	102	207.3	11.7	4.9	105	319	37	187	0.43
4/5	101	209.8	12	4.9	114	328	41	192	0.45
4/6	238	446.3	7.7	9.7	51	375	18	220	0.51
4/7	248	460.2	6.3	11.2	44	355	15	208	0.48
4/8	263	483.1	6.3	11.1	50	352	17	206	0.48
4/9	322	605.3	5.9	11.8	48	396	17	232	0.54
4/10	325	609	5.2	12.5	47	372	17	218	0.51
4/11	194	596.9	5.2	12.3	69	354	24	208	0.48
4/12	252	467.3	6.1	11.5	58	350	20	205	0.48
4/13	263	495.9	6.4	11.1	72	356	26	209	0.49
4/14	358	680.5	5.1	12.4	78	409	27	240	0.56
4/15	350	669.3	5.6	12.1	-	416	-	244	0.57
4/16	356	681.2	4.9	12.4	33	397	12	233	0.54
4/17	359	690.5	5	12.4	29	391	10	230	0.53
4/18	267	509.2	7.4	10.1	54	400	19	235	0.55
4/19	298	556.9	5.7	12	39	387	14	227	0.53
4/20	350	683	6.1	11.9	54	383	19	225	0.52
4/21	349	660	5.4	12.7	58	411	21	241	0.56
4/22	359	664	4.8	12.7	52	408	18	239	0.56
4/23	353	662.5	5	12.5	44	401	16	235	0.55
4/24	371	651.3	4.9	12.7	79	413	28	242	0.56

* Dashes indicate "No Data."

** February 28 and March 1: Plant Shut-down for maintenance.

***March 5 to March 26: Labor strike.

A statistical analysis of the data was performed to determine the distribution characteristics of the 24-hour averages and to calculate the statistical parameters. The normal distribution statistical parameters are presented in Table F-III-4 for all the 24-hour averages, and show, for Test No. 2, for example, that the mean value of stack oxygen content was 6.1 percent with a standard deviation of 1.7 percent. The mean NO value for Test No. 2 (as equivalent NO₂) was 220 ng/J with a standard deviation of 14.5, or 7 percent of the mean value. Other statistical data for Test No. 2 may be found in Table F-III-5. A comparison between Tables F-III-5 and F-III-4 shows that deviations in NO_x data are reduced when the data are separated by load range.

The 24-hour average data were plotted as a function of time from the start of testing. Figure F-III-1 shows the variation in boiler thermal and electric load as a function of time from the start of the first test, during which the average thermal load varied from 191.3 MW_{th} (approximately 23 percent of rated capacity) to 773 MW_{th} (94 percent of rated capacity). The daily average electrical output had a mean value of 284.4 MW_e or 67 percent of rated capacity and varied from 24 to 94 percent of rated electrical capacity (425 MW_e, gross). The daily averages used in this figure were obtained from the unit operators. The two curves do not always match and the reason is not clear. The most obvious mismatch is about the eighteenth or nineteenth days where the steam flow is high and the electrical output is low.

Similarly, the thermal and electric load data for the second test are shown on Figure F-III-2. Here, the daily average boiler thermal load varied from a minimum of 207 MW_{th} (707.5 x 10³ lb steam/hr) to about 700 MW_{th} (about 2400 lb steam/hr).

Figures F-III-3 through F-III-6 show the gaseous emissions (O₂, NO, CO₂, and CO) as a function of time for Test No. 1. Similarly Figures F-III-7 through F-III-10 show the same information for Test No. 2. CO is measured because it is a very sensitive indicator of combustion conditions. The concentration of CO as a function of time for Test No. 1 (Figure F-III-6) shows that the CO concentration was very near zero for the entire period indicating essentially complete combustion. The average CO emission rate for the entire period was only 2.6 ng/J (7 ppm) with only two periods over 10 ng/J (27 ppm) which corresponds to periods when the excess O₂ was quite low. During Test No. 2, although the CO data shows a good deal of scatter, the range is quite low and higher values represent only approximately 100 ppm. The higher values of CO were recorded when the boiler load was very low; a condition under which control of the burners is very difficult. The effect of excess oxygen on the CO emission rate during Test No. 2 shows that for high excess oxygen conditions (very low load) the CO emission rate is highest. In this case, O₂ had the opposite effect on CO as compared with Test No. 1, and indicates that mixing is not efficient at low loads. If the combustion process is uniform and efficient, very low values of CO will result.

TABLE F-III-4							
NORMAL DISTRIBUTION STATISTICAL PARAMETERS							
		Load (MW _{th})	O ₂ (%)	CO ₂ (%)	CO (ng/J)	NO*	
						(ng/J)	(lb/MBtu)
Mean	1st Test	478.3	7.3	11.2	2.6	208	0.48
	2nd Test	557.7	6.1	11.5	15	220	0.51
Standard Deviation	1st Test	182.6	2.4	2.5	4.6	20.2	0.05
	2nd Test	129.7	1.7	2.0	9.2	14.5	0.03
Maximum	1st Test	773.4	11.8	15.2	19.0	248	0.58
	2nd Test	718.1	12.0	14.0	41	244	0.57
Minimum	1st Test	191.3	4.2	6.4	0	155	0.36
	2nd Test	207.3	4.2	4.9	0	187	0.43
Range	1st Test	582.1	7.6	8.8	19.0	93	0.22
	2nd Test	510.8	7.8	9.1	41	57	0.14

TABLE F-III-5					
SUMMARY OF BOILER EMISSIONS AS A FUNCTION OF BOILER LOAD					
STATISTICAL PARAMETERS FOR TEST NO. 2					
Boiler Load (MW _{th})	O ₂ (%) Mean	NO Emissions (ng/J)*			
		Mean	Std. Dev.	% Dev.	Range
828-662	5.1	234	7.2	3%	20
661-497	5.7	224	11.5	5%	36
496-331	6.9	209	5.7	3%	15
<331	10.7	198	14.9	7.5%	28
Rated Boiler Capacity = 828 MW _{th} = 2826 x 10 ³ lb/hr steam flow					

*As NO₂

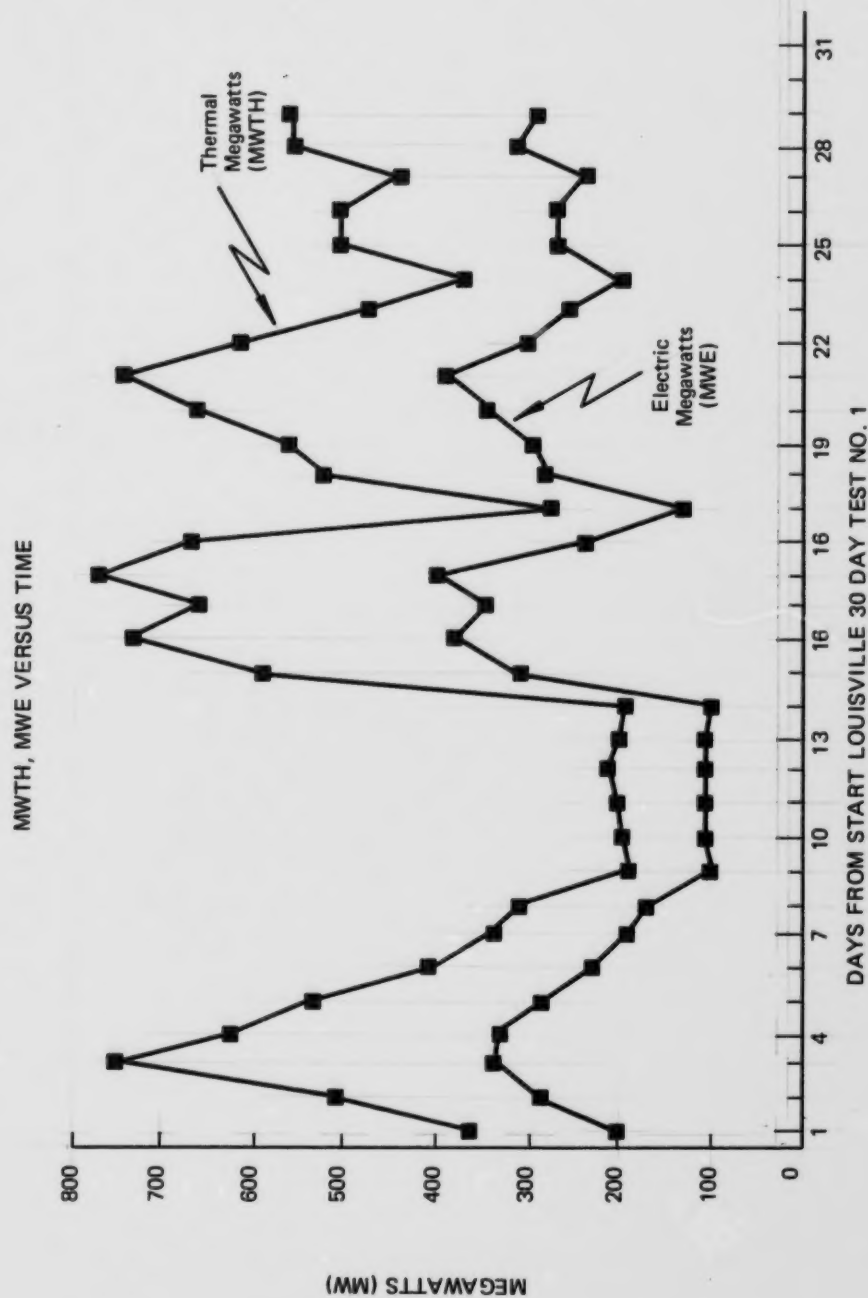


Figure F-III-1. Test No. 1
DAILY AVERAGE BOILER STEAM LOAD AND ELECTRICAL OUTPUT
AS A FUNCTION OF TIME FROM START OF TESTING

MWTH, MWE VERSUS TIME

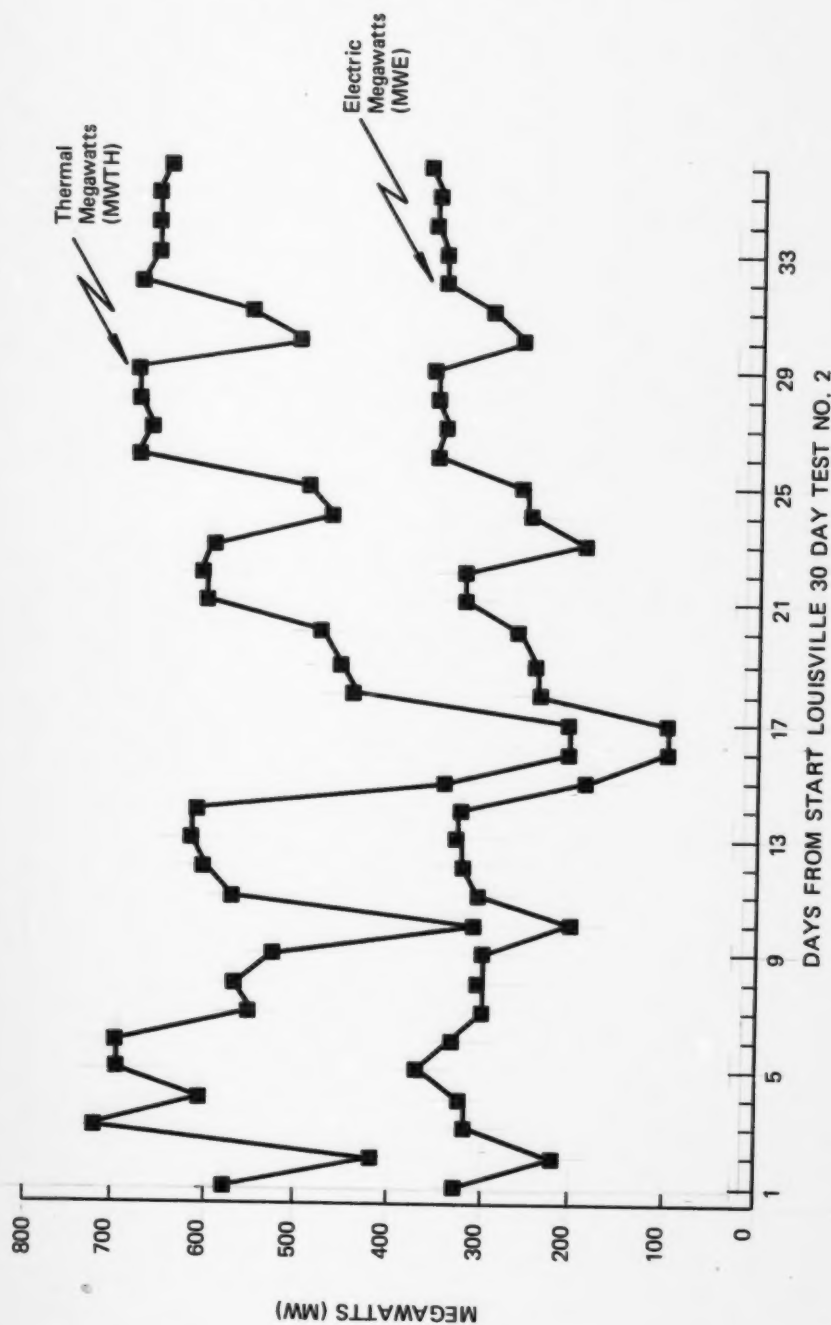
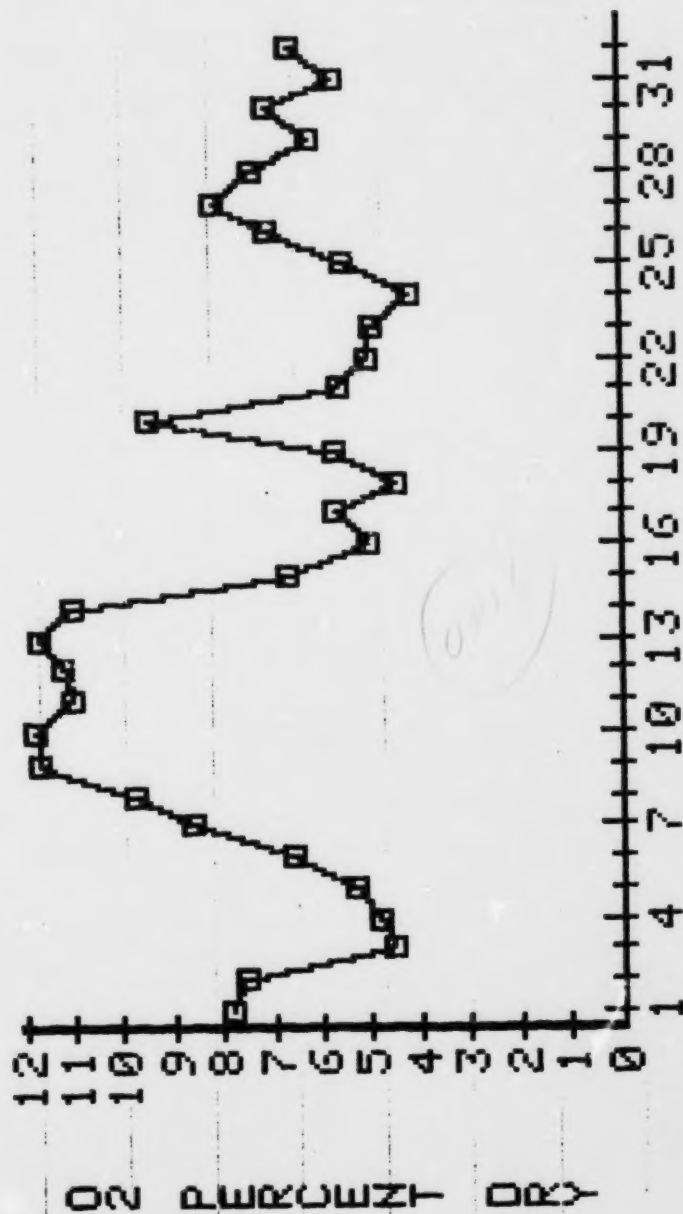


Figure F-III-2. Test No. 2
COMPARISON OF DAILY AVERAGE THERMAL LOAD AND ELECTRICAL OUTPUT
AS A FUNCTION OF TIME FROM START OF TESTING

02 VERSUS TIME

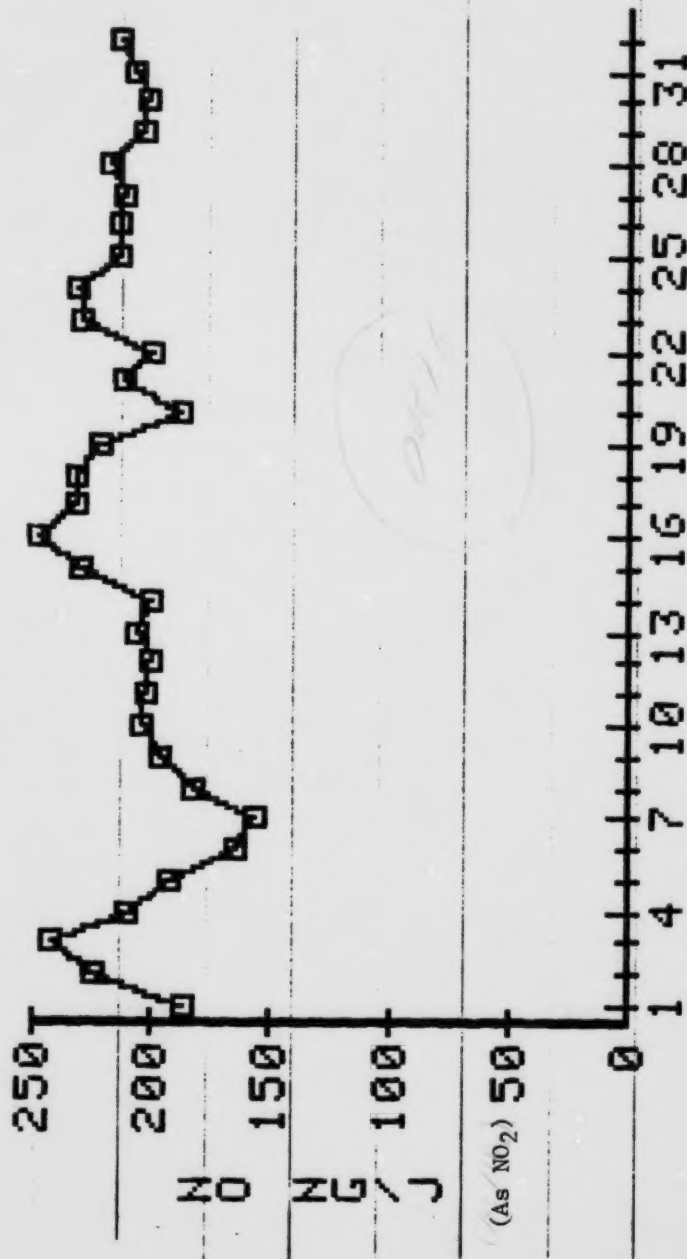


DAYS FROM START

LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-3. Test No. 1: Daily average stack oxygen concentration as a function of time from start of testing.

NO VERSUS TIME

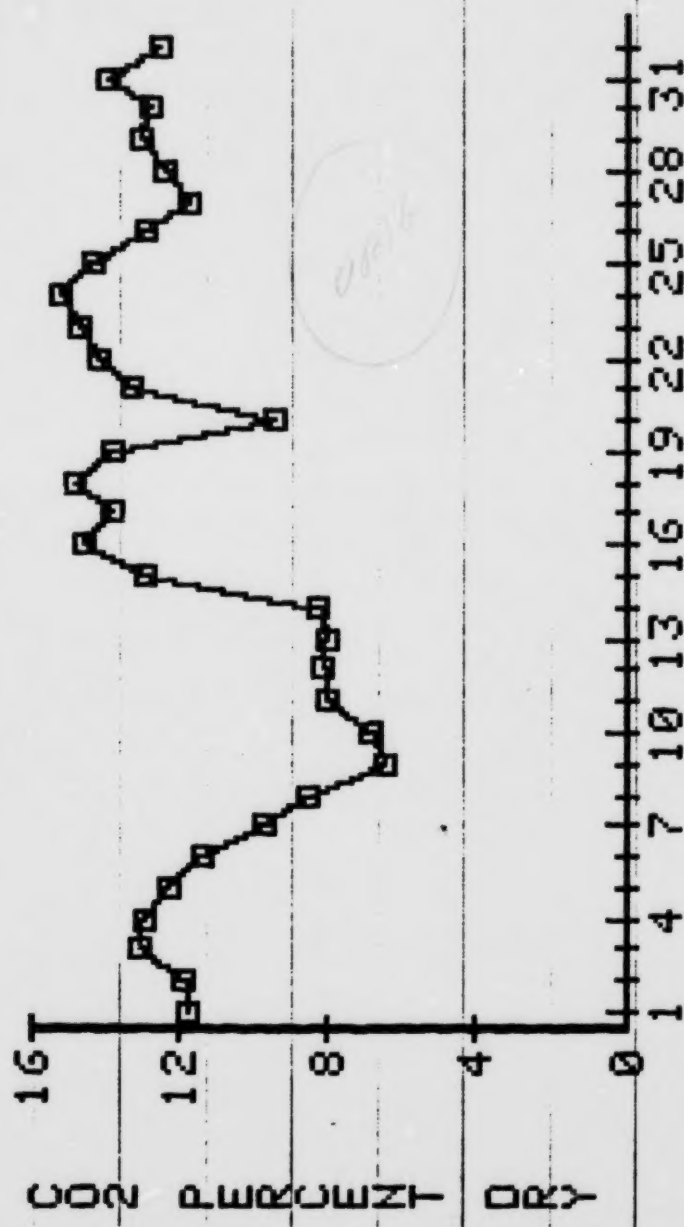


DAYS FROM START

LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-4. Test No. 1: Daily average NO emission rate as a function of time from start of testing.

CO2 VERSUS TIME

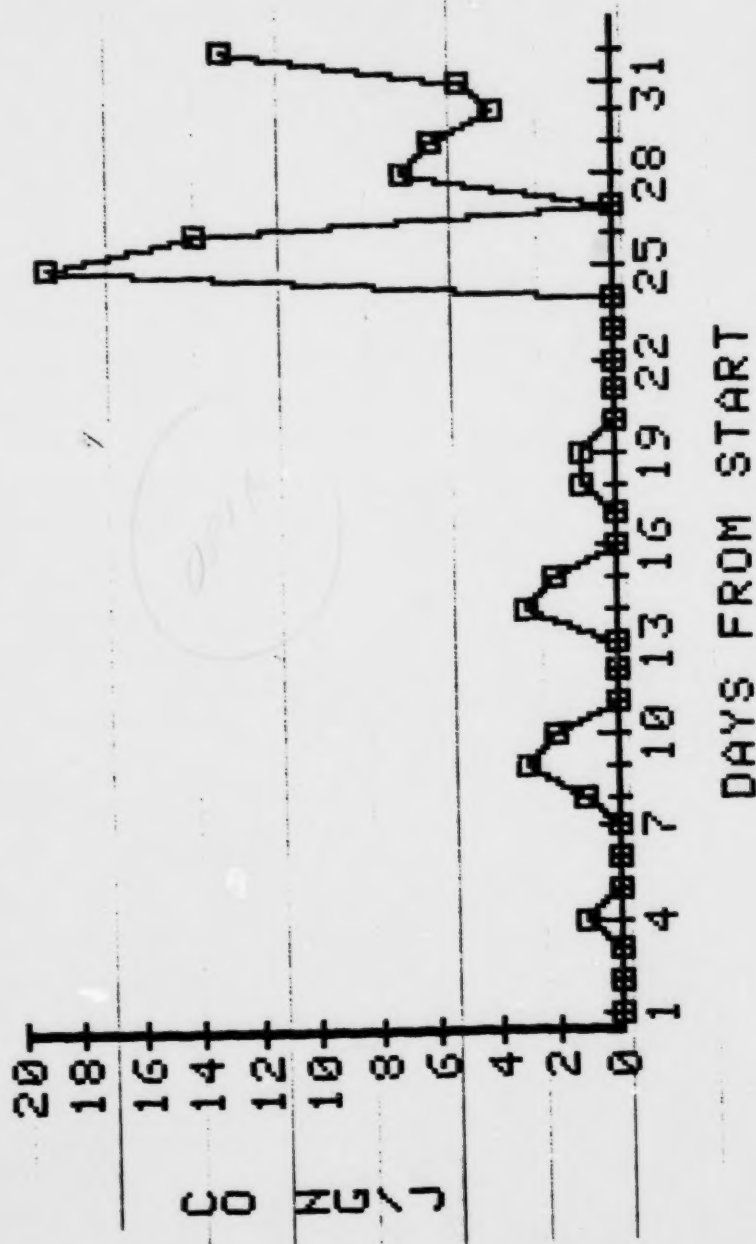


DAYS FROM START

LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-5. Test No. 1: Daily average CO₂ concentration as a function of time from start of testing.

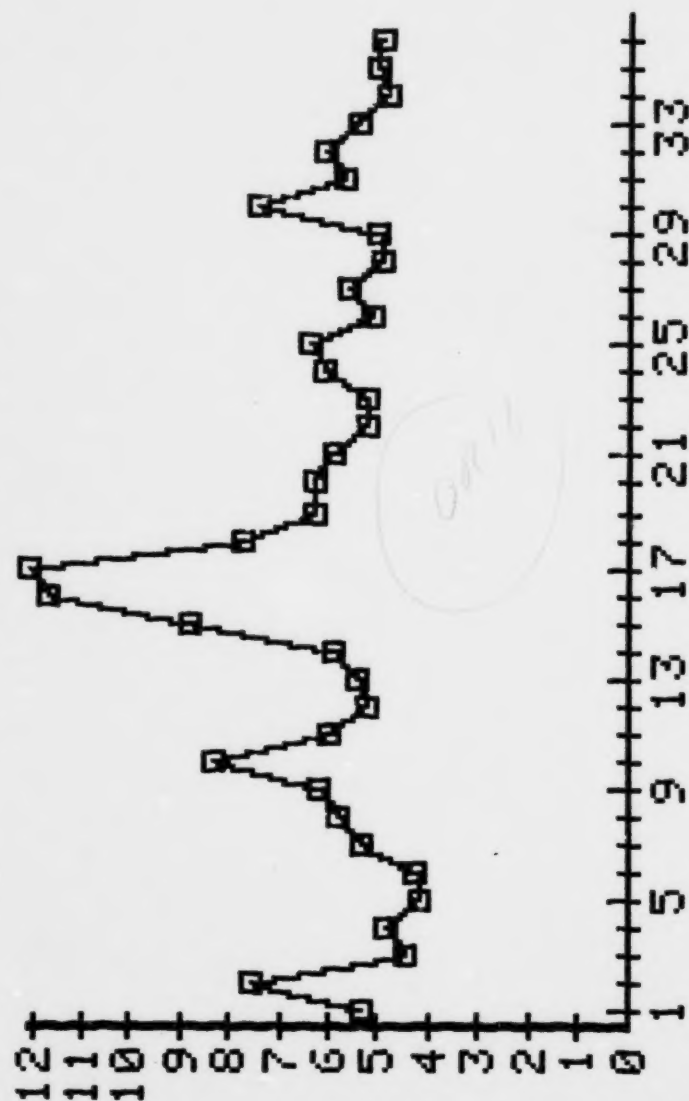
CO VERSUS TIME



LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-6. Test No. 1: Daily average CO emission rate as a function of time from start of testing.

02 VERSUS TIME



DAYS FROM START OF TEST

LOUISVILLE 30 DAY TEST NO. 2

Figure F-III-7. Test No. 2: Daily Average Stack Oxygen Content as a Function of Time.

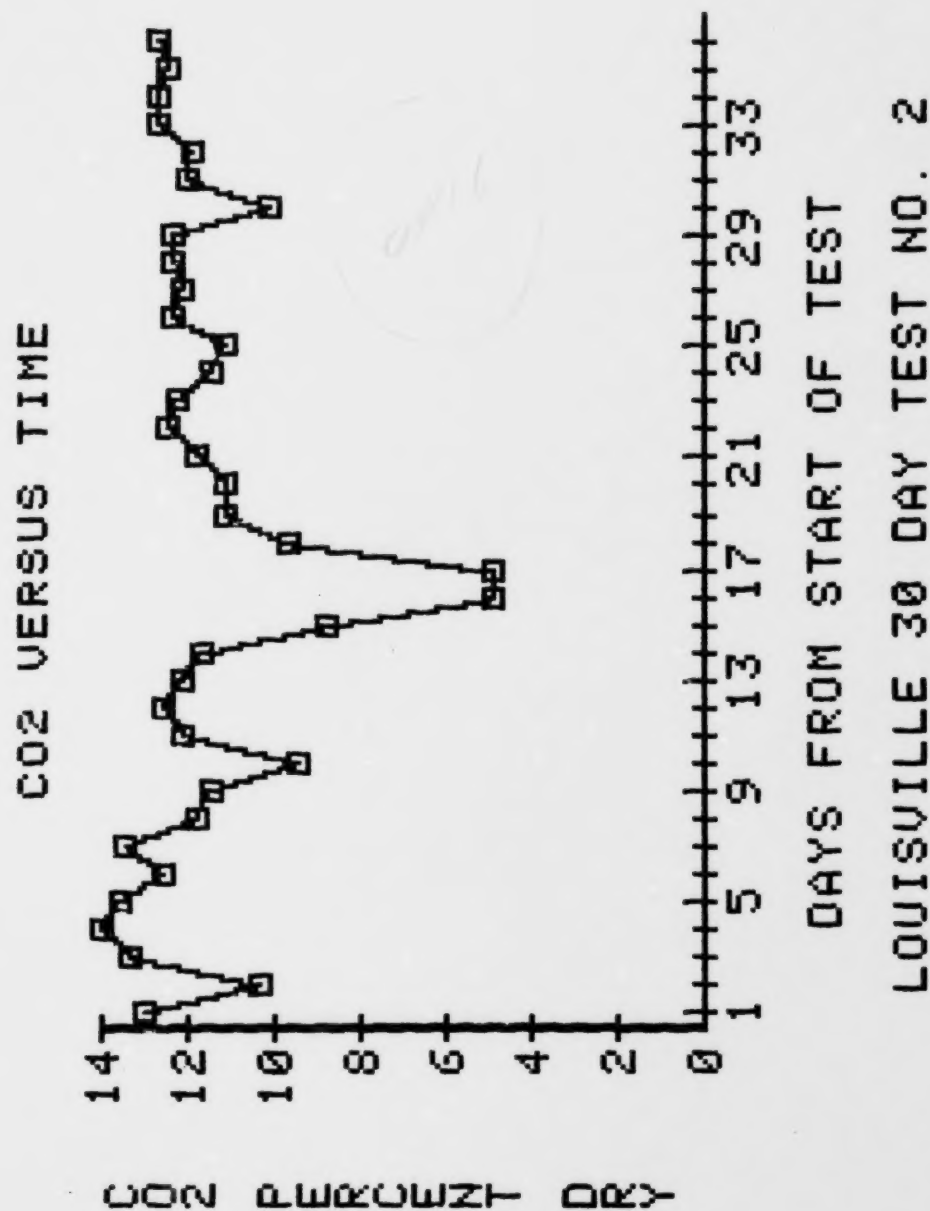
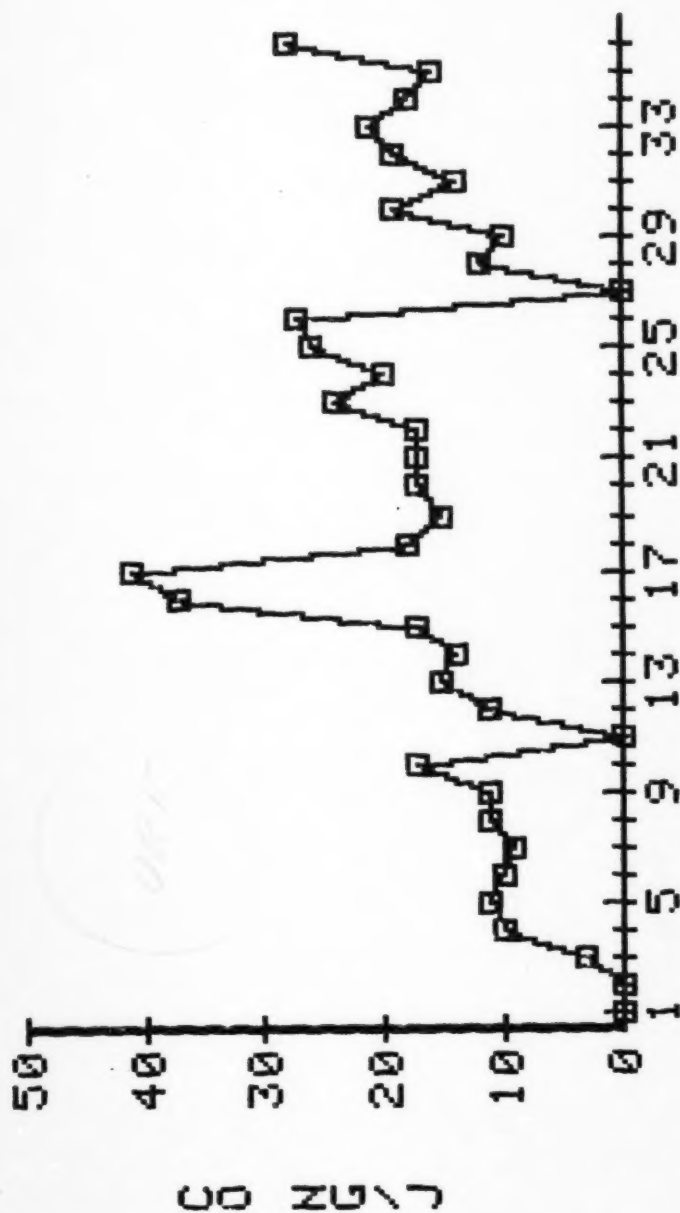


Figure F-III-8. Test No. 2: The Daily Average CO₂ as a Function of Time from Start of Testing.

CO VERSUS TIME



DAYS FROM START OF TEST
LOUISVILLE 30 DAY TEST NO. 2

Figure F-III-9. Test No. 2: Daily Average CO Emission Rate as a Function of Time from Start of Testing.

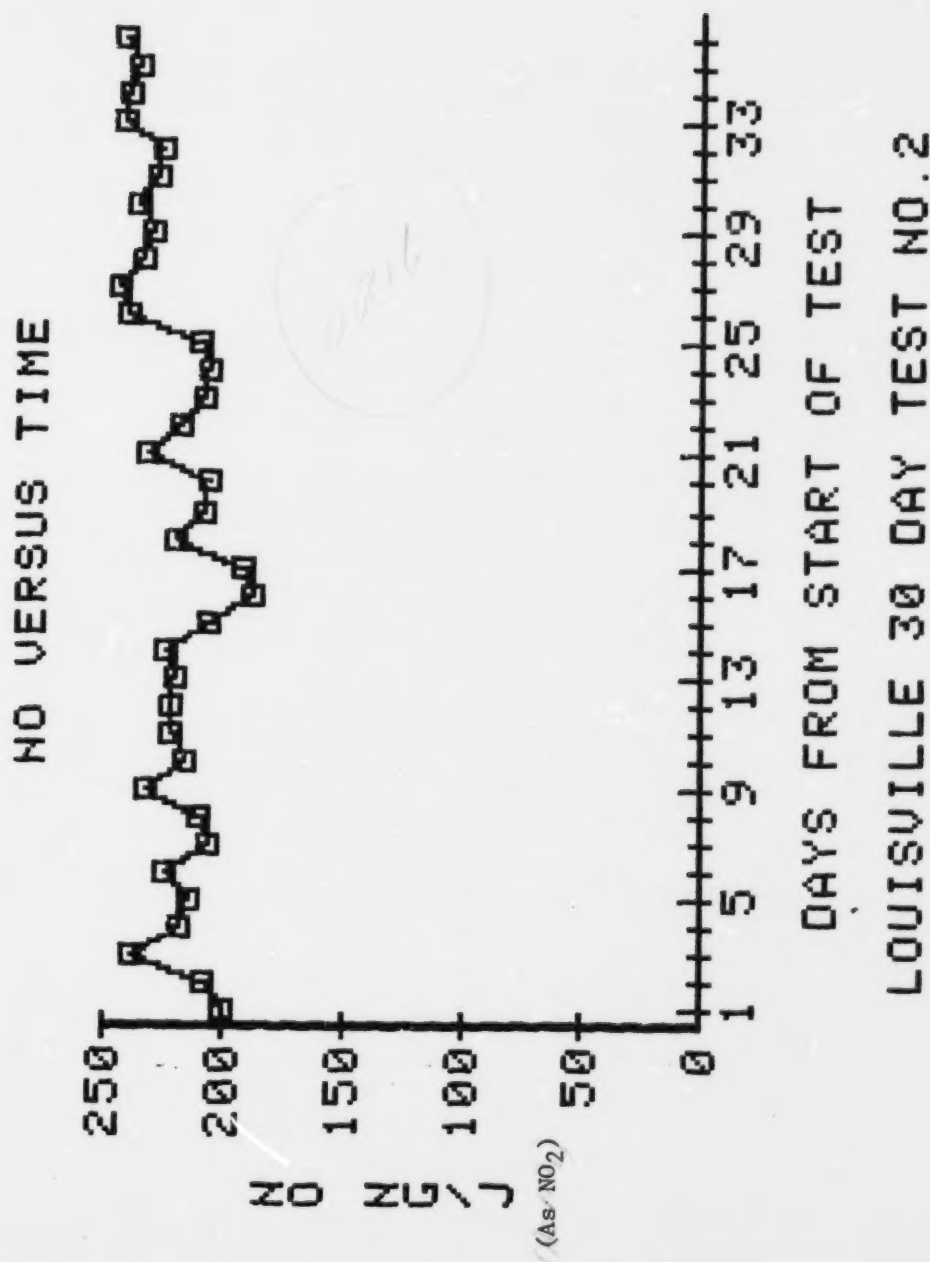


Figure F-III-10. Test No. 2: Daily Average NO Emission Rate as a Function of Time from Start of Testing.

Generally, the periods of high excess O_2 correspond to periods of low boiler load. The effects of boiler load on excess oxygen (an independently controlled effect) and on NO emission rates are shown in Figures F-III-11 and F-III-12 for the first test, and Figures F-III-13 and F-III-14 for the second test. These data show that boiler steam load has a strong effect on excess O_2 . (For example, see Figure F-III-11.) A linear regression analysis of data from Test No. 1 showed that boiler O_2 is a linear function of boiler load within the range of the data. A correlation coefficient, r^2 , of 0.907 was obtained from the regression analysis. The effect of boiler load and boiler excess O_2 on NO emission rate was plotted in Figures F-III-11 and F-III-12, respectively. Again, linear regression analyses were performed on the data and little correlation was determined between NO-Load and NO- O_2 , perhaps because the O_2 selected is somewhat dependent on load. The correlation coefficients were 0.452 and 0.229, respectively. A multiple linear regression analysis with both load and O_2 as independent variables showed a fairly good correlation. The multiple linear regression analysis resulted in the following equation for NO emission rate:

$$NO = -24.6 + 2.59 (LOAD) + 14.876 (O_2)$$

and the correlation coefficient $r^2 = 0.737$. The units (ng/J NO as NO_2 , MW_{th} , and ppm O_2 dry) are the same as on Figures F-III-11 through F-III-14.

It should be noted that although O_2 and load are treated as being independent of each other in the analysis above, that is not always true. A similar exercise performed on data from Test No. 2 (Figure F-III-13) showed a linear relationship between O_2 and load.

$$O_2 = (13.265) - (0.12) (LOAD)$$

where: Load = MW_{th}
 O_2 = percent, dry

The reader may now wish to substitute this expression for O_2 (in terms of load) into the above expression for NO to give an expression for NO strictly in terms of load, but with a somewhat degraded correlation factor (r^2).

Generally, one would expect the NO_x emission rate (expressed in "ng/J") to decrease as load decreases due to the cooler temperatures inside the furnace at the lower loads. However, as load is decreased, the amount of excess air is increased (for safety's sake), and this tends to increase the NO_x production. The two effects together tend to nullify each other, and the NO_x vs. load trend lines (Figures F-III-12 and F-III-14) are nearly horizontal.

A linear regression exercise was performed on O_2 vs. CO_2 data for Test No. 2 (Figure F-III-15) and revealed a very good linear fit ($r^2 = 0.961$).

$$O_2 = 18.33 - 1.109 (CO_2)$$

121<

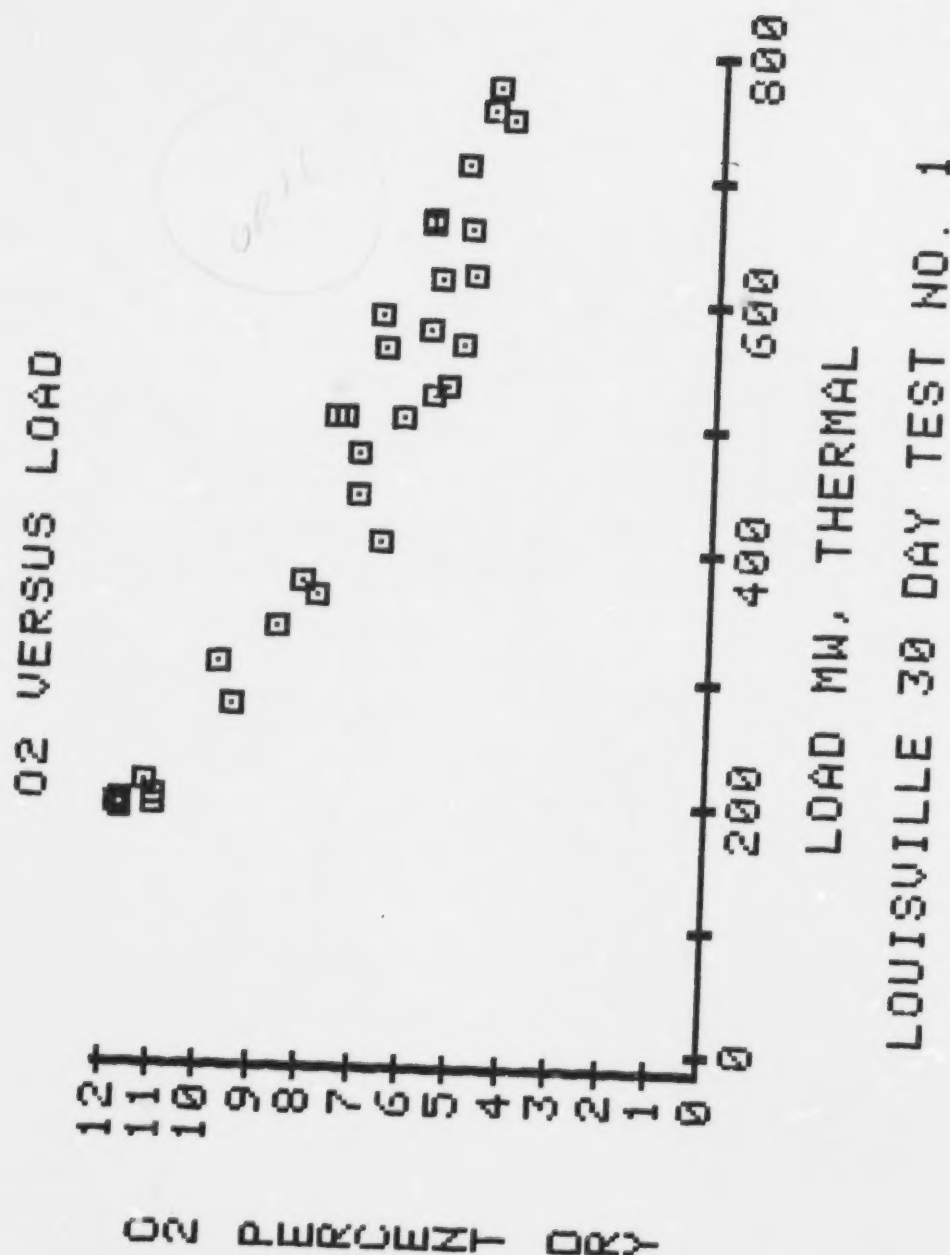
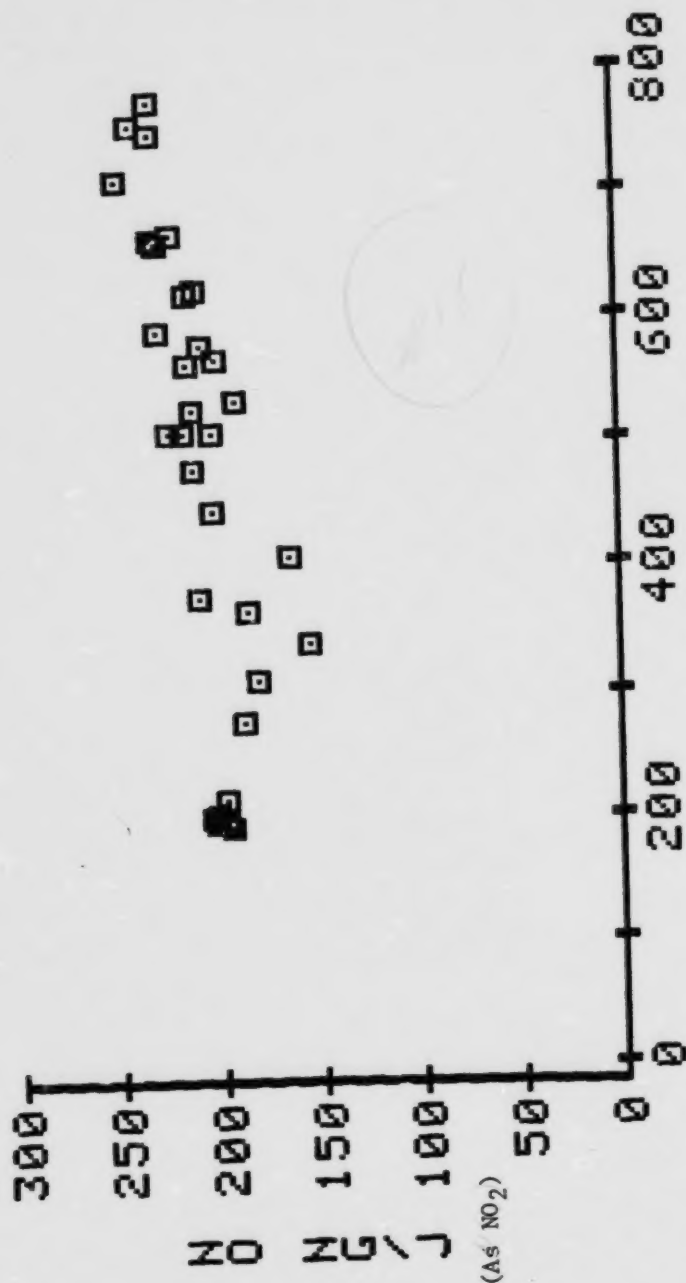


Figure F-III-11. Test No. 1: Stack Oxygen Concentration as a Function of Boiler Steam Load.

NO VERSUS LOAD

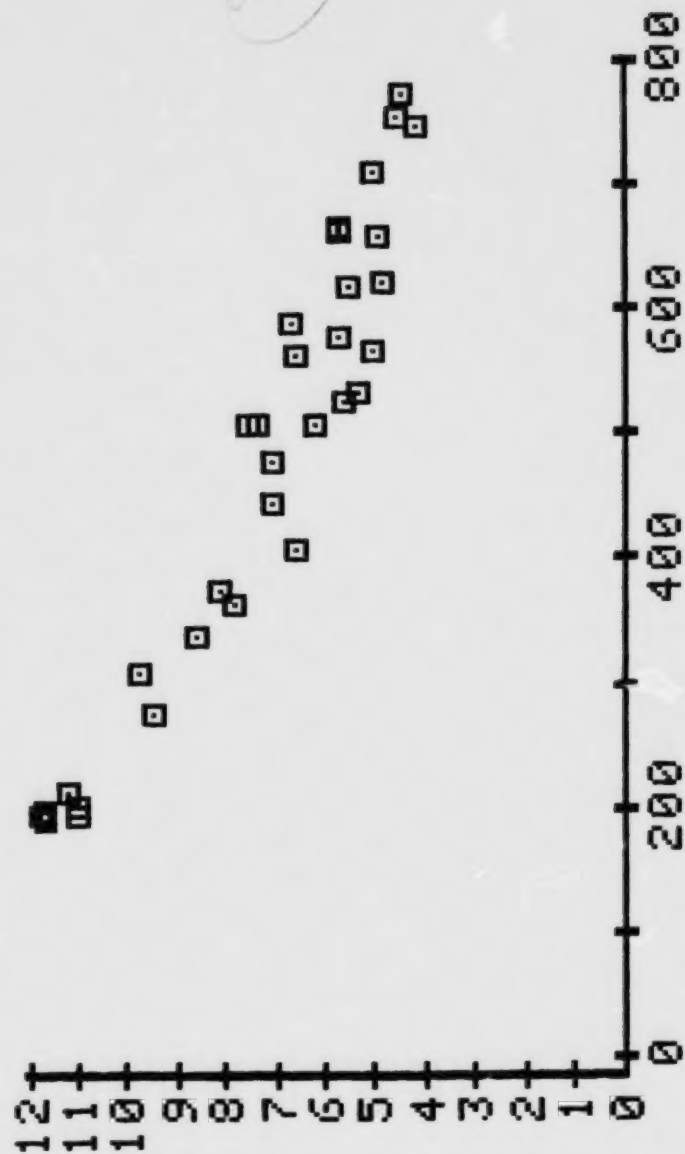


LOAD MW, THERMAL

LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-12. Test No. 1: NO emission rate as a function of boiler steam load.

O₂ VERSUS LOAD



BOILER LOAD MW THERMAL

LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-13. Test No. 2: The effect of Boiler Steam Load on Stack Excess Oxygen.

NO VERSUS LOAD



LOUISVILLE 30 DAY TEST NO. 2

Figure F-III-14. Test No. 2: Daily Average NO Emission Rate as a Function of Boiler Load.

O₂ VERSUS CO₂



CO₂ PERCENT DRY

LOUISVILLE 30 DAY TEST NO. 2

Figure F-III-15. Test No. 2: The Effect of CO₂ on Stack Excess O₂.

where: O_2 = percent, dry
 CO_2 = percent, dry

The high correlation factor indicates that when O_2 data is missing, the CO_2 data may be used instead by appropriate use of the above formula. EPA has recognized the strong dependence between O_2 and CO_2 , and allows either one to be used as the dilution term when calculating emission rates.

A similar analysis on data from Test No. 1, confirmed the validity of this method.

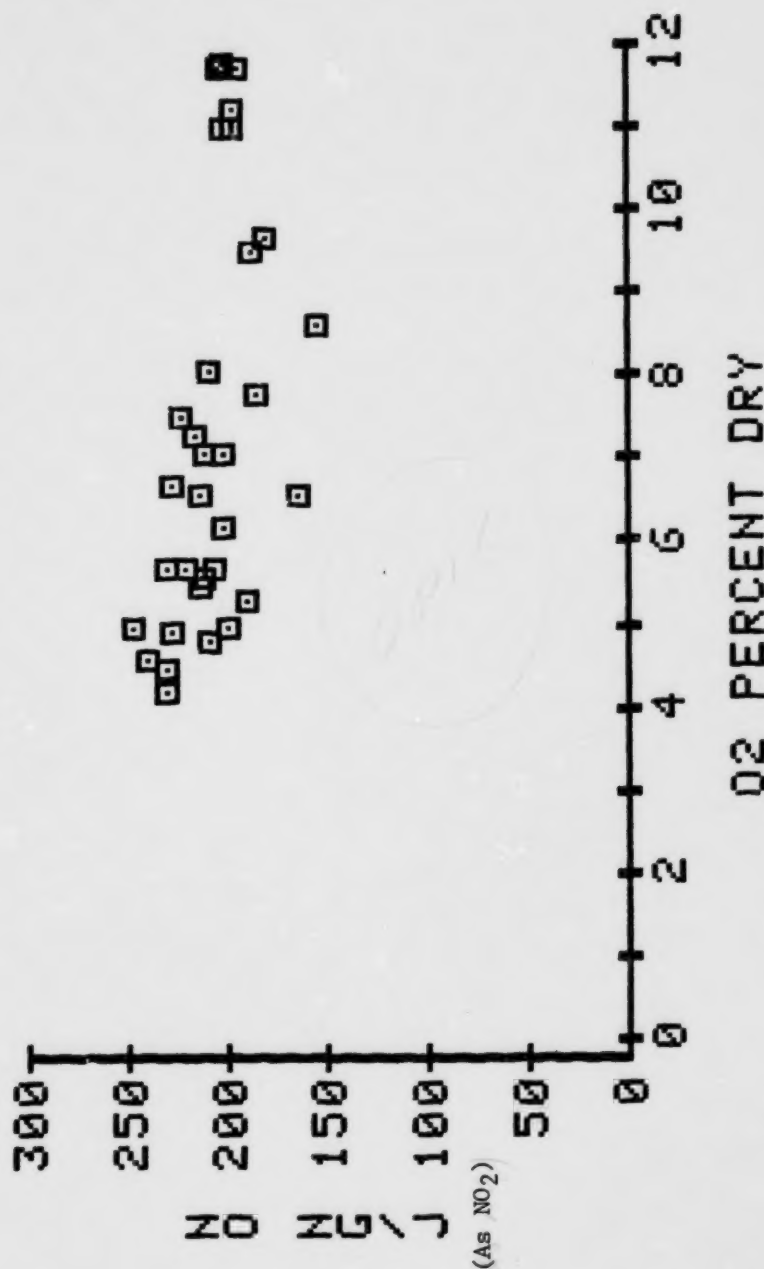
The NO emission rate vs. stack excess oxygen (without consideration of load, etc.) is presented in Figures F-III-16 and F-III-17. Although there is considerable scatter in the data, the expected trend is for an increase in NO emissions with increasing excess oxygen. However, this trend is tempered by the fact that increased oxygen concentration (a NO_x promoter) occurs most often at low loads (a NO_x retardant). Consequently, the NO_x vs. O_2 curves shown here (which include all loads) have a much smaller slope than the curves shown in part B of this report (where the data was separated by load before being plotted).

For Test No. 2, the daily average NO emission rate (Figure F-III-10) did not exhibit much variation over the test period. The mean value was 220 ng/J (as NO_2) with a standard deviation of 14.47 and was relatively insensitive to variations in boiler load (Figure F-III-14). The NO emission rate for Test No. 2 was approximately 22 percent lower at low load conditions than at high load conditions. Figure F-III-17 shows a general decrease in NO with increasing excess oxygen although there is quite a lot of scatter in the data. This is opposite to the expected trend because, as explained earlier, the data was not sorted by load, and the two effects compete in opposite directions. Hence, a linear regression analysis on the NO vs. O_2 data for Test No. 2 (Figure F-III-17) did not show a good correlation. The calculated correlation coefficient was only 0.532.

A statistical analysis* was performed on the 24-hour averages to determine the distribution characteristics and to calculate the statistical parameters. The normal distribution statistical parameters are presented in Table F-III-4. All data were used to calculate these parameters regardless of boiler load. The 24-hour averages for Test No. 1 were plotted first on normal probability paper (Figure F-III-18) using all the data, regardless of boiler load. The mean NO value (as NO_2) was determined from the graph to be 206 ng/J (0.48 lb/ 10^6 Btu). The calculated mean NO value (as NO_2) was 208 ng/J (0.49 lb/ 10^6 Btu) with a standard deviation of 20.2. This standard

*The mean is the Y intercept at 50 percent value. The geometric dispersion in a log-normal distribution plays an equivalent role to a standard deviation for a normal distribution. The geometric dispersion is the ratio of the 93.3 percent and 6.7 percent "less than" values, raised to the 1/3 power.

NO VERSUS O2



LOUISVILLE 30 DAY TEST NO. 1

Figure F-III-16. Test No. 1: NO emission rate as a function of stack oxygen concentration.

NO VERSUS EXCESS O2



02 PERCENT DRY

LOUISVILLE 30 DAY TEST NO. 2

Figure F-III-17. Test No. 2: NO Emission Rate as a Function of Stack Excess Oxygen.

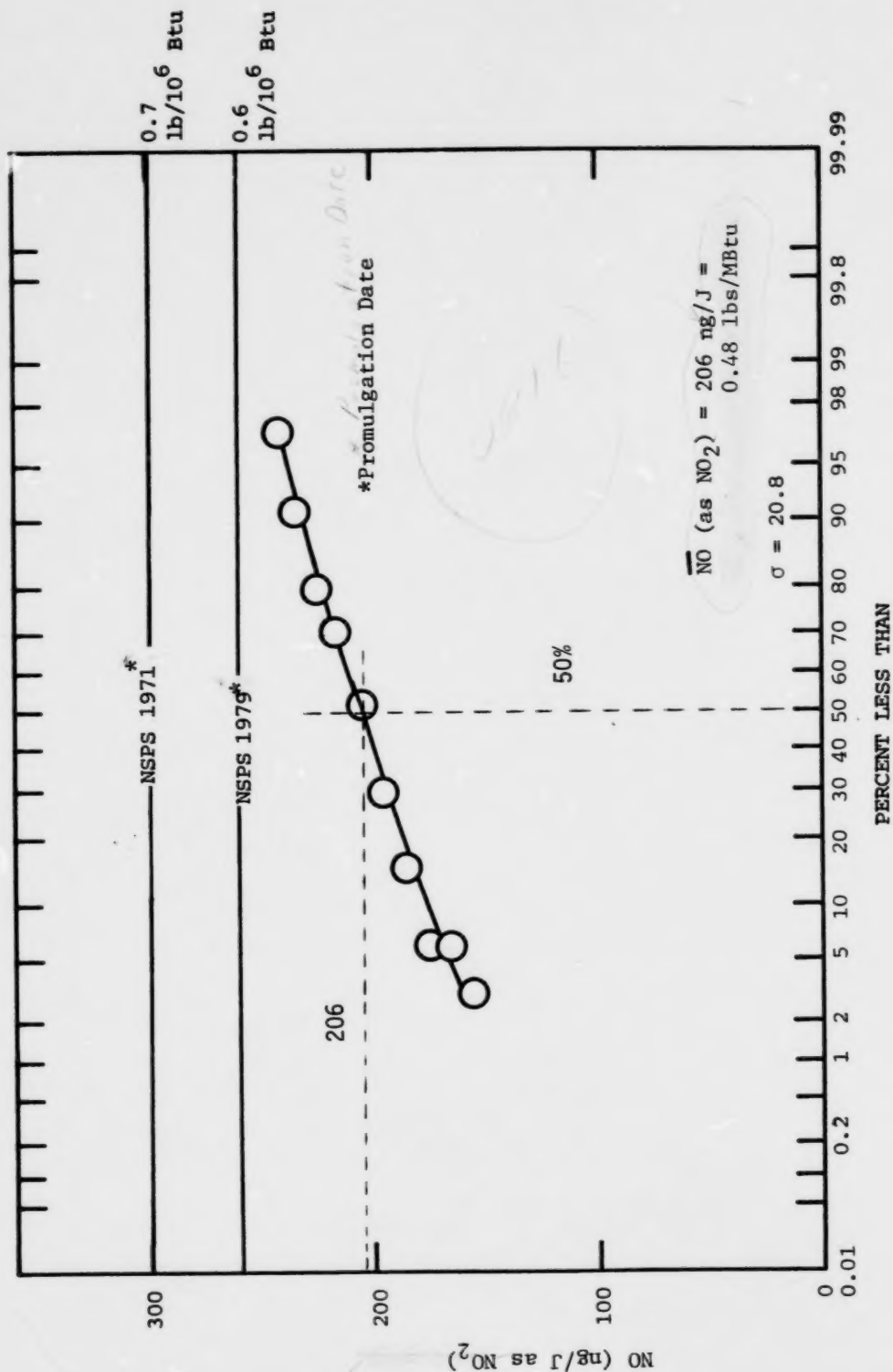


Figure F-III-18. Test No. 1: Normal probability curve of NO emissions rate - Louisville Gas and Electric Co., Mill Creek Unit 3.

a 10 percent deviation from the mean. The data were then plotted on log-probability paper (Figure F-III-19), and gave a better fit. Using the log-probability curve for all the data, the mean value of NO emissions was determined to be 202 ng/J (0.47 lb/10⁶ Btu) with a geometric dispersion of 1.02.

A similar analysis was also made using data from Test No. 2. The 24-hour NO emission averages for Test No. 2 were plotted on probability paper (Figure F-III-20) using data from all boiler loads, and show that the mean value (as NO₂) is 221 ng/J (0.51 lb/10⁶ Btu) (determined from the graphical analysis). This compares to the calculated value of 220 ng/J. Since the plot of the data shows a slight curve rather than a straight line, another distribution, other than normal, is indicated. The data were then plotted on log-probability coordinates (Figure F-III-21) and the result is a straight line with a mean NO value (as NO₂) of 220 ng/J (0.51 lb/10⁶ Btu) and a geometric dispersion of 1.07. These data indicate that 99 percent of the values are less than 250 ng/J (0.58 lb/10⁶ Btu). This is well below the maximum limits set by any NSPS issued so far. (For the reader's convenience, the NSPS limits are superimposed on Figures F-III-18 through F-III-20.)

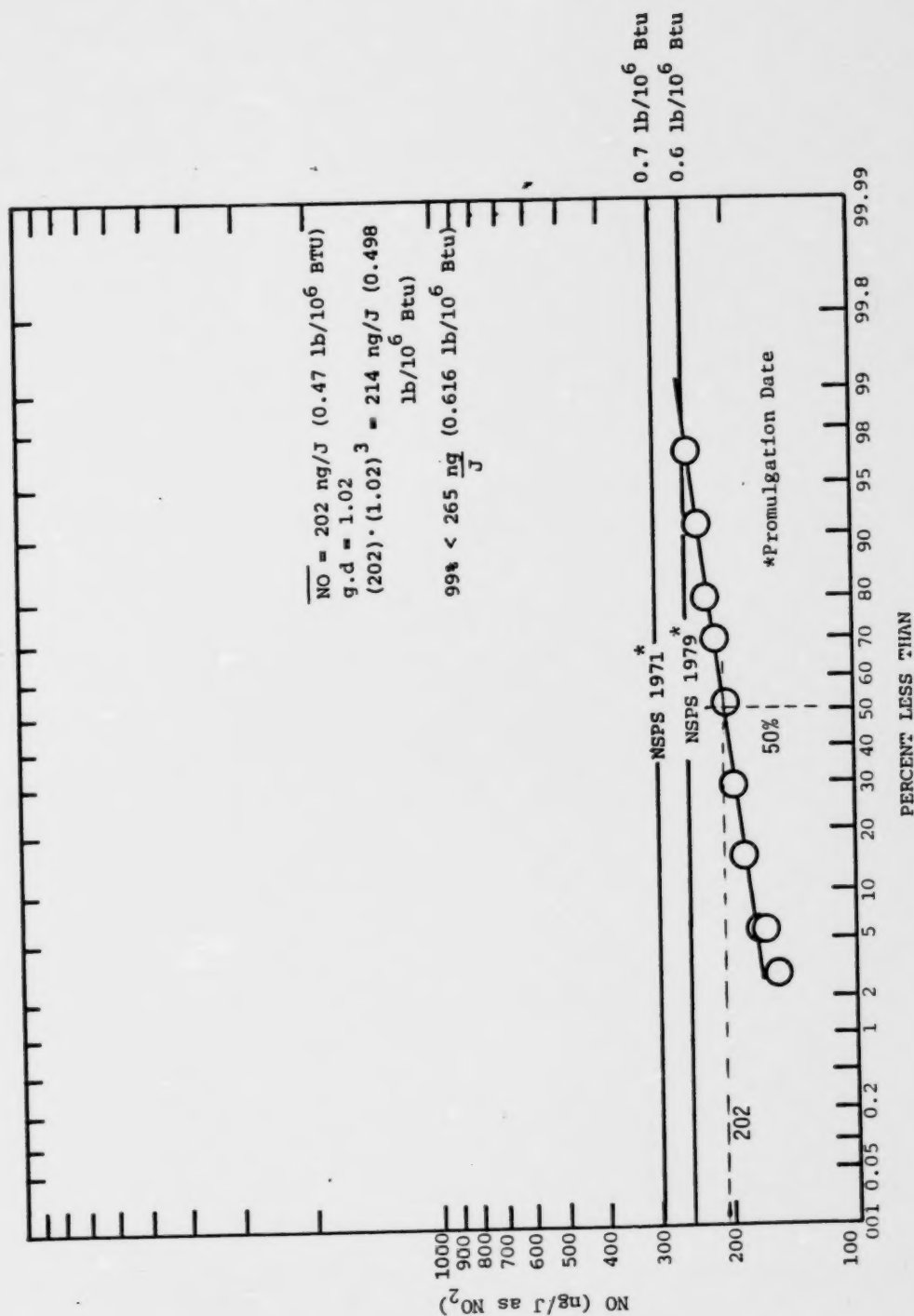


Figure F-III-19. Test No. 1: Log-Probability curve of NO emission - Louisville Gas & Electric Co., Mill Creek No. 3; January 18 - February 20, 1981.

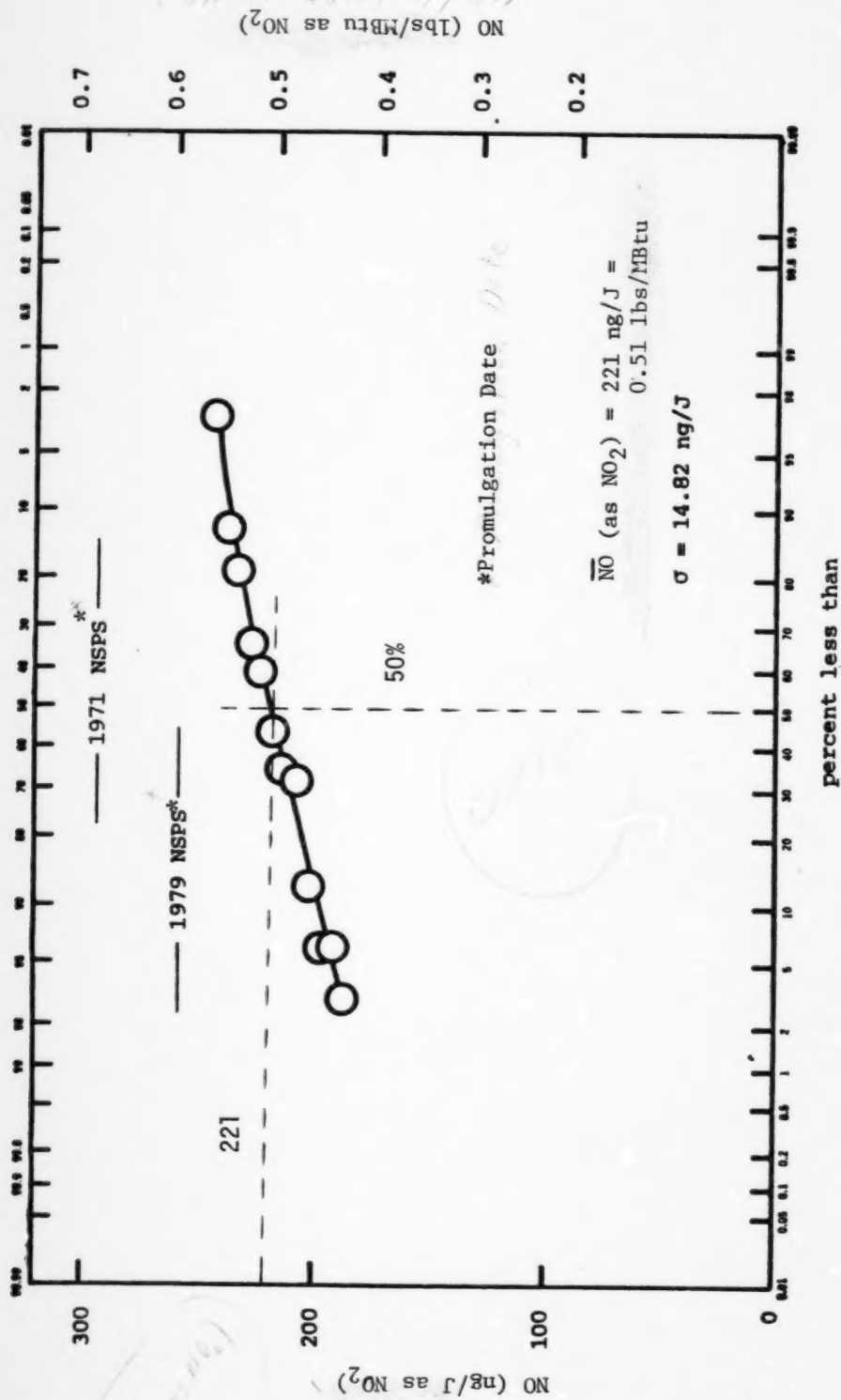


Figure F-III-20. Test No. 2: Normal probability curve of NO emissions, Louisville Gas & Electric Co., Mill Creek No. 3, 30-day Test No. 2

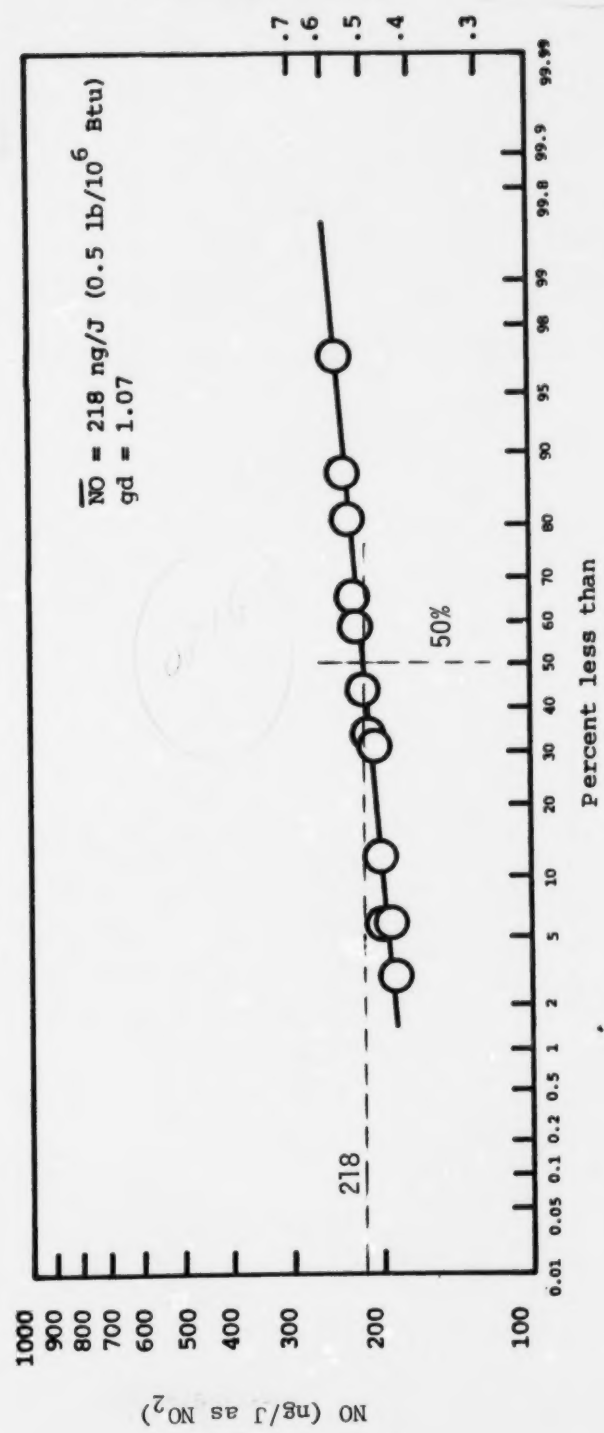


Figure F-III-21. Test No. 2: Log probability curve of NO emissions, Louisville Gas & Electric, Mill Creek No. 3, 30-day Test No. 2.

PART G

APPENDIXES

APPENDIX A

CONTROL ROOM BOARD DATA

Due to the large volume of boiler operating data, it is impractical to present all such data here. Instead, the data sheets from Tests 46-49 have been selected as representative, and are presented in the following pages.

The data describe the operation of the boiler during each test.

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

		Units	Log Code	46	47	48
Test Number				46	47	48
Date		M-D-Y		10-9-80		10-10-80
Time		Military (24 hr)		1016		1008
Purpose				Basis for Gas Taps	Gas Tap Test	First SO ₂ /SO ₃ Test
Excess Air				Normal		Normal
FGR to Hopper Flow				0		ON
FGR to Windbox Flow				0		0
Main Steam Flow (Turbine 1st Stage)	A	KP/HR	T104	2664		2281
	B	KP/HR	T105	2647		2273
Main Steam Pressure		PSI	CR	2410		2410
Main Steam Temp. (avg)		°F	B102CA	993		1001
Gross Load (From Board)		MW	G100CA	403		370
Number of Mills in Service			A154	3		3
Mills on air only				B		B
Mills off (no coal, no air)				-		-
Spin vane settings (closed ⇒ spin)		%open				
Inner register settings		%open				
Outer register settings		%open				
FUEL FLOW		A	KP/HR	D129	110	102
		B	KP/HR	D130	0	-
		C	KP/HR	D131	108	101
		D	KP/HR	D132	103	97
		TOTAL	KP/HR	NA	321.0	300.0
PULVERIZER AMPS		A	AMPS	CR	90	87
		B	AMPS	CR	0	0
		C	AMPS	CR	90	92
		D	AMPS	CR	90	92
AIR FLOW	Secondary	A	KP/HR	D165	1294	1205
		B	KP/HR	D166	1550	1403
		TOTAL	KP/HR	D181	2849	2605
	Total by Mills (Secondary & Primary)	A	%MCR	CR	83	75
		B	%MCR	CR	13	12
		C	%MCR	CR	84	85
		D	%MCR	CR	81	82

This gas tap test was run immediately after and at the same conditions as flue gas Test No. 46

CA = Continuous average
 CR = Control room
 MCR = Maximum continuous rating
 NA = Not available

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

				Units	Log Code			
Test Number						46	47	48
Date				M-D-Y		10-9-80		10-10-80
Time				Military (24 hr)		1017		1017
AIR FLOW (Continued)	Primary	A		KP/HR	D167	487		434
		B		KP/HR	D168	11.9		13.7
		C		KP/HR	D169	491		440
		D		KP/HR	D170	492		444
	Secondary	A	A	KP/HR	D173	349		325
			B	KP/HR	D171	69.6		69
			C	KP/HR	D172	359		337
			D	KP/HR	D174	343		313
		B	A	KP/HR	D177	368		342
			B	KP/HR	D175	68		67
			C	KP/HR	D176	367		329
			D	KP/HR	D178	366		336
PRIMARY AIR FAN AMPS			A	AMPS	CR	96		92
			B	AMPS	CR	0		0
			C	AMPS	CR	104		97
			D	AMPS	CR	100		94
PRIMARY AIR FLOW CONTROLS (DAMPER POSITIONS)			A	Zopen	CR	75		70
			B	Zopen	CR	0		0
			C	Zopen	CR	78		75
			D	Zopen	CR	76		75
PRIMARY AIR ATTEMPERATOR DAMPER POSITIONS (HOT/COLD)			A	Zopen	CR	46		45
			B	Zopen	CR	0		0
			C	Zopen	CR	42		42
			D	Zopen	CR	39		37
FEEDWATER FLOW				KP/HR	F118	2646		2166
MAIN STEAM FLOW (FIRST STAGE)				KP/HR	CR	265		225
MAIN STEAM FLOW (CALCULATED)				KP/HR	T732	2624		2223
HIGH PRES. EXTRACTION (Doesn't include F. W. Heaters)		Soot Blowers		0-40	CR	3.6		3.5
		ARs + IKs		KP/HR	(G)			
		Air Heater		0-30	CR	1.5		1.5
		Blower		KP/HR	(R)			
REHEAT STEAM FLOW				KP/HR	NA			
CONDENSATE FLOW				KP/HR	F153CA	2300		1995
S. H. SPRAY FLOW				KP/HR	B143CA	0		176
S. H. SPRAY VALVE POSITION		A	Zopen	CR		21		44
		B	Zopen	CR		23		56

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

		Units	Log Code	46	47	48
Test Number				46	47	48
Date		M-D-Y		10-9-80		10-10-80
Time		Military (24 hr)		1019		1023
RH SPRAY FLOW		KP/HR	B188	0		0
RH SPRAY VALVE POSITION		Open	CR	0		0
WATER FLOW TO WATER COOLED AIR HEATER (W.C.A.H)	A	KP/HR	D110CA	56.8		57
	B	KP/HR	D111CA	54.7		72
FLUE GAS RECIRC. FAN	Speed	RPM	NA			
	AMPS	AMPS	CR	0		118
	Bus voltage	VOLTS	NA			
FGR DAMPER SYSTEM	Inlet Damper Pos.	Open	CR	0		118
	SA Damper	A	Open	CR	0	0
	Position	B	Open	CR	0	0
	Hopper Damper Pos.	Open	CR	0		23
WATER TO ECONOMIZER (F.W.) PRES.		PSI	F119	2662		2603
DRUM PRESSURE		PSI	B221CA	2558		2515
MAIN STEAM PRESSURE		PSI	B111CA	2394		2397
COLD REHEAT STEAM PRES.		PSI	B190CA	524		455
HOT REHEAT STEAM PRES.		PSI	B159CA	469		407
STEAM PRESSURE (steam chest)		PSI	T113	2338		2287
TURBINE 1st STAGE PRESSURE		PSI	T102CA	1601		1352
FD FAN DISCG. PRES.	A	"H ₂ O	D100	10.2		10.1
	B	"H ₂ O	D101	10.9		10.5
MILL DIFFERENTIAL ΔP PRESSURE DROP	A	"H ₂ O	CR	15		12
	B	"H ₂ O	CR	0		0
	C	"H ₂ O	CR	17		15
	D	"H ₂ O	CR	16		14
Water Cooled Air Heater ΔP	A	"H ₂ O	D124	0.81		0.74
	B	"H ₂ O	D125	1.18		0.97
SEC. AIR DUCT PRESS.	A	"H ₂ O	D157	6.93		7.11
	B	"H ₂ O	D158	6.99		7.18

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

Test Number		Units	Log Code	46	47	48
Date		M-D-Y		10-9-80		10-10-80
Time		Military (24 hr)		1029		1034
WINDBOX PRESSURE	A	"H ₂ O	D118	2.27		2.00
	B	"H ₂ O	D119	-		-
	C	"H ₂ O	D120	2.97		2.48
	D	"H ₂ O	D121	2.58		2.25
UPPER FURNACE DRAFT		"H ₂ O	D140	-0.9		-0.71
SH-RH ΔPRESSURE (DRAFT)		"H ₂ O	D141	0.6		0.90
ECONOMIZER ΔPRESSURE		"H ₂ O	D139	-0.1		0.78
GAS ΔP AT MAIN AIR HTRS	A	"H ₂ O	D153	4.76		4.39
	B	"H ₂ O	D154	4.04		3.39
GAS TO PRECIPITATOR	A	"H ₂ O	NA			
	B	"H ₂ O	NA			
I.D. FAN PRES.	IN	A	"H ₂ O	D160	-11.1	-10.5
		B	"H ₂ O	D161	-10.8	-9.7
	OUT	A	"H ₂ O	NA		
		B	"H ₂ O	NA		
SCRUBBER OUTLET PRES.	A	"H ₂ O	NA			
	B	"H ₂ O	NA			
ATMOSPHERIC PRESSURE		"Hg	A106	29.30		29.32
AMBIENT AIR TEMP		°F	A100CA	67		63
AMBIENT AIR REL. HUMIDITY		°F	A101CA	81		76
WATER COIL AIR HEATER AIR INLET TEMP.	A	°F	D105CA	96		92
	B	°F	D106CA	93		89
MAIN AIR HEATER AIR TEMPS	IN	A	°F	D114CA	119	117
		B	°F	D115CA	117	121
	OUT	A	°F	D116CA	531	522
		B	°F	D117CA	519	512
PRIMARY AIR FAN INLET TEMPERATURES (Fan outlet temp. = Mill inlet temp)	A	°F	On Mills	337		335
	B	°F	On Mills	95		90
	C	°F	On Mills	308		300
	D	°F	On Mills	317		305

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

				Units	Log Code			
Test Number						46	47	48
Date				M-D-Y		10-9-80		10-10-80
Time				Military (24 hr)		1030		1037
PRIMARY AIR FAN OUTLET TEMPERATURES (CONTINUED)				A	°F	NA		
				B	°F	NA		
				C	°F	NA		
				D	°F	NA		
PULVERIZER TEMPERATURES		IN	A	°F	NA			
			B	°F	NA			
			C	°F	NA			
			D	°F	NA			
		OUT	A	°F	D135	148		145
			B	°F	D136	102		96
			C	°F	D137	142		142
			D	°F	D138	144		144
FLUE GAS TEMPERATURES	SH OUTLET			°F	NA			
	RH OUTLET			°F	NA			
	ECONOMIZER OUTLET		A	°F	NA			
			B	°F	NA			
	MAIN AIR HTR	IN	A	°F	D145CA	626		611
			B	°F	D146CA	639		622
		OUT	A	°F	D147CA	311		304
			B	°F	D148CA	305		299
	PRECIPITATOR OUTLET		A	°F	NA			
			B	°F	NA			
	I. D. FAN OUTLET		A	°F	NA			
			B	°F	NA			
	SCRUBBER OUTLET		A	°F	NA			
			B	°F	NA			
	STACK TEMP.			°F	D199	170		169
WATER COIL AIR HEATER WATER TEMPERATURE		IN		°F	D107	294		300
		OUT	A	°F	D108	138		139
			B	°F	D109	119		132
ECONOMIZER FEEDWATER TEMPERATURES		IN		°F	F100CA	464		451
		OUT	A	°F	B226	559		578
			B	°F	B227	571		590
BOILER FEEDWATER PUMP SUCTION				°F	F136	367		356

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

				Units	Log Code			
Test Number						46	47	48
Date				M-D-Y		10-9-80		10-10-80
Time				Military (24 hr)		1031		1039
PRIMARY SH OUTLET STEAM TEMPERATURE				A	°F	B146	711	733
				B	°F	B147	717	738
PRIMARY SH STEAM AFTER SPRAY		IN	A	°F	B138	699	690	
			B	°F	B139	699	691	
		OUT	A	°F	B132	734	724	
			B	°F	B133	732	726	
SECONDARY SH STEAM OUTLET TEMP.				°F	B106	985	994	
REHEAT STEAM TEMP.	COLD IN			°F	B189CA	607	588	
	ATTEMPERATION SECTION STEAM TEMPERATURE	IN	A	°F	NA			
			B	°F	NA			
		OUT	A	°F	NA			
			B	°F	NA			
	HOT (OUT)			°F	B155	—	—	
CALCULATED REHEAT SPRAY TEMP.				°F	B186	369	358	
MAIN STEAM TEMP.				°F	B102	995	1004	
WINDBOX O ₂			A	%	D155			
			B	%	D156			
			AVG		NA			
BOILER EXIT GAS O ₂			A	%	NA			
			B	%	NA			
			AVG	%	D103	4.75	5.00	
SO ₂	ENTERING SCRUBBER			PPM	P186CA	2639	2442	
	LEAVING SCRUBBER			PPM	P194CA	875	829	
FLUE GAS NO _x				PPM	P195	364	361	
FLUE GAS OPACITY		ELECTRONIC		%	D198	43.8	35.7	
		SMOKE READER		%	PSN			
STACK O ₂				%MCR	CR	60	68	
BOILER EFFICIENCY		HEAT-LOSS METHOD		%	A715			
		IN - OUT METHOD		%	A716	87.6	86.9	
GROSS UNIT HEAT RATE				Btu KW · HR	A700			

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

		Units	Log Code			
Test Number				46	47	48
Date		M-D-Y		10-9-80		10-10-80
Time		Military (24 hr)		1033		1042
HIGH PRESSURE FEEDWATER HEATERS	FW LEAVING No. 1	°F	F180CA	175		168
	FW ENTERING No. 1	°F	F184CA	122		114
	No. 1 HEATER DRAIN	°F	F183CA	176		169
	STEAM TO No. 1 HTR	°F	F181CA	190		193
	STEAM TO No. 1 HTR	PSI	F182CA	7.3		6.36
SH OUTLET LEG TC	(Header No. 1, LEG 12)	°F	B402	968		965
RH OUTLET LEG TC's	(Header No. 1, BOT LEG)	°F	B409	907		919
	(Header No. 10, REAR LEG)	°F	B428	921		935

Notes: During test No. 48 the flue gas fan was on, and load was increased from 358 to 380 during the test.

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

		Units	Log Code	49	49	49	49	AVG For Test 49
Test Number				10-15-80	10-15-80	10-15-80	10-15-80	
Date		M-D-Y						
Time		Military (24 hr)		1042	1540	1737	2100	
Purpose				LEVEL 1 TEST (AS FOUND), B MILL OFF				
Excess Air				Normal	Normal	Normal	Normal	
FGR to Hopper				0	0	0	0	
FGR to Windbox				0	0	0	0	
Main Steam Flow (Turbine 1st Stage)	A	KP/HR	T104	2762	2752	2750	2769	
	B	KP/HR	T105	2755	2744	2712	2759	
Main Steam Pressure		PSI	CR	2404	2403	2414	2409	
Main Steam Temp. (avg)		°F	B102CA	1004	1006	1002	1005	
Gross Load (From Board)		MW	G100CA	418	418	418	418	
Number of Mills in Service			A154	3	3	3	3	
Mills on air only				B	B	B	B	
Mills off (no coal, no air)				-	-	-	-	
Spin vane settings (closed → spin)		↑open		as per PSN's notebook				
Inner register settings		↑open						
Outer register settings		↑open						
FUEL FLOW	A	KP/HR	D129	115	123	125	119	359
	B	KP/HR	D130	—	—	—	—	
	C	KP/HR	D131	113	121	124	117	
	D	KP/HR	D132	108	115	119	113	
	TOTAL		NA					
PULVERIZER AMPS	A	AMPS	CR	90	90	90	89	
	B	AMPS	CR	0	0	0	0	
	C	AMPS	CR	92	92	92	92	
	D	AMPS	CR	92	90	89	96	
	TOTAL	KP/HR	D181	2935	3099	3226	3005	
AIR FLOW	Secondary	A	KP/HR	D165	1391	1466	1523	1410
		B	KP/HR	D166	1534	1641	1703	1582
	Total by Mills (Secondary & Primary)	A	↑MCR	CR	83	89	89	85
		B	↑MCR	CR	13	13	13	13
		C	↑MCR	CR	83	90	89	85
		D	↑MCR	CR	81	87	88	83

CA = Continuous average

CR = Control room

MCR = Maximum continuous rating

NA = Not available

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

			Units	Log Code					
Test Number					49	49	49	49	
Date			M-D-Y		10-15-80	10-15-80	10-15-80	10-15-80	
Time			Military (24 hr)						
					1053	1542	1747	2104	
AIR FLOW (Continued)	Primary		A	KP/HR	D167	496	533	555	510
			B	KP/HR	D168	13	11	105	11.6
			C	KP/HR	D169	493	533	560	514
			D	KP/HR	D170	472	503	521	490
	Secondary	A	A	KP/HR	D173	362	388	414	378
			B	KP/HR	D171	69	68.3	69	69
			C	KP/HR	D172	376	397	406	377
			D	KP/HR	D174	358	385	407	369
		B	A	KP/HR	D177	366	400	403	376
			B	KP/HR	D175	70	71.9	74.1	71
			C	KP/HR	D176	356	392	409	318
			D	KP/HR	D178	368	392	404	377
PRIMARY AIR FAN AMPS			A	AMPS	CR	95	100	97	97
			B	AMPS	CR	0	0	0	0
			C	AMPS	CR	97	100	100	103
			D	AMPS	CR	94	100	96	97
PRIMARY AIR FLOW CONTROLS (DAMPER POSITIONS)			A	%open	CR	79	85	83	81
			B	%open	CR	0	0	0	0
			C	%open	CR	77	87	87	83
			D	%open	CR	77	80	78	80
PRIMARY AIR ATTEMPERATOR DAMPER POSITIONS (HOT/COLD)			A	%open	CR	53	47	48	48
			B	%open	CR	0	0	0	0
			C	%open	CR	46	46	46	44
			D	%open	CR	53	44	47	48
FEEDWATER FLOW			KP/HR	F118	2662	2586	2592	2593	
MAIN STEAM FLOW (FIRST STAGE)			KP/HR	CR	275	275	276	273	
MAIN STEAM FLOW (CALCULATED)			KP/HR	T732	2715	2694	2698	2701	
HIGH PRES. EXTRACTION (Doesn't include F. W. Heaters)	Soot Blower		0-40	CR	0	0	0	0	
	ARs & IKs		KP/HR	(G)					
	Air Heater		0-30	CR	0	0	0	10	
Blower			KP/HR	(R)					
REHEAT STEAM FLOW			KP/HR	NA					
CONDENSATE FLOW			KP/HR	F153CA	2364	2341	2385	2367	
S. H. SPRAY FLOW			KP/HR	B143CA	ON	177.2	79.8	15.9	
S. H. SPRAY VALVE POSITION			A	%open	CR	35	46	40	42
			B	%open	CR	31	52	45	50

MILL CREEK NO. 3
CONTROL ROOM BOARD DATA
(CONTINUED)

Test Number		Units	Log Code	49	49	49	49
Date		M-D-Y		10-15-80	10-15-80	10-15-80	10-15-80
Time		Military (24 hr)		1055	1551	1748	2109
RH SPRAY FLOW		KP/HR	B188	0	0	0	0
RH SPRAY VALVE POSITION		%open	CR	0	29	0	0
WATER FLOW TO WATER COOL'ED AIR HEATER	A	KP/HR	D110CA	89	56.6	56.7	61
	B	KP/HR	D111CA	64	58.9	58.3	59
FLUE GAS RECIRC. FAN	Speed	RPM	NA				
	AMPS	AMPS	CR	0	0	0	0
	Bus voltage	VOLTS	NA				
FGR DAMPER SYSTEM	Inlet Damper Pos.	%open	CR	0	0	0	0
	SA Damper Position A	%open	CR	0	0	0	0
	Position B	%open	CR	0	0	0	0
	Hopper Damper Pos.	%open	CR	0	0	0	0
WATER TO ECONOMIZER (F.W. PRES.)		PSI	F119	2669	2667	2603	2675
DRUM PRESSURE		PSI	B221CA	2568	2554	2515	2567
MAIN STEAM PRESSURE		PSI	B111CA	2394	2385	2397	2395
COLD REHEAT STEAM PRES.		PSI	B190CA	544	544	455	542
HOT REHEAT STEAM PRES.		PSI	B159CA	486	491	407	487
STEAM PRESSURE (steam chest)		PSI	T113	2352	2346	2287	2336
TURBINE 1st STAGE PRESSURE		PSI	T102CA	1672	1652	1352	1663
FD FAN DISCG. PRES.	A	"H ₂ O	D100	10.8	11.0	11.4	10.9
	B	"H ₂ O	D101	10.7	11.3	11.6	11.2
MILL DIFFERENTIAL ΔP PRESSURE DROP	A	"H ₂ O	CR	16	18	18	17
	B	"H ₂ O	CR	0	0	0	0
	C	"H ₂ O	CR	14	20	21	20
	D	"H ₂ O	CR	15	17	16	17
WATER COOLED AIR HEATER ΔP	A	"H ₂ O	D124	0.99	1.1	1.2	0.98
	B	"H ₂ O	D125	1.15	1.3	1.3	1.2
SEC. AIR DUCT PRES.	A	"H ₂ O	D157	7.11	7.0	7.1	7.3
	B	"H ₂ O	D158	7.07	7.0	7.1	7.3

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

		Units	Log Code	49	49	49	49
Test Number				10-15-80	10-15-80	10-15-80	10-15-80
Date		M-D-Y					
Time		Military (24 hr)		1056	1552	1749	2111
WINDBOX PRESSURE	A	"H ₂ O	D118	2.26	2.8	2.8	2.6
	B	"H ₂ O	D119	-	-	-	-
	C	"H ₂ O	D120	2.92	3.5	3.6	3.3
	D	"H ₂ O	D121	2.58	3.2	3.4	2.98
UPPER FURNACE DRAFT		"H ₂ O	D140	-0.84	-1	-1.1	-1.15
SH-RH ΔPRESSURE (DRAFT)		"H ₂ O	D141	-	-	-	-
ECONOMIZER ΔPRESSURE		"H ₂ O	D139	-	-	-	-
GAS ΔP AT MAIN AIR HTRS	A	"H ₂ O	D153	4.47	5.45	5.4	4.72
	B	"H ₂ O	D154	3.95	4.51	5.0	4.44
GAS TO PRECIPITATOR	A	"H ₂ O	NA				
	B	"H ₂ O	NA				
I D. FAN PRES.	IN	A	"H ₂ O	D160	-11.2	13.3	-13.2
		B	"H ₂ O	D161	-11.3	-12.9	-13.4
	OUT	A	"H ₂ O	NA			
		B	"H ₂ O	NA			
SCRUBBER OUTLET PRES.	A	"H ₂ O	NA				
	B	"H ₂ O	NA				
ATMOSPHERIC PRESSURE		"Hg	A106	29.52	29.45	29.44	29.46
AMBIENT AIR TEMP		°F	A100CA	64	80	82	69
AMBIENT AIR REL. HUMIDITY		°F	A101CA	65	46	44	60
WATER COIL AIR HEATER AIR INLET TEMP.	A	°F	D105CA	92	102	103	100
	B	°F	D106CA	89	99	100	97
MAIN AIR HEATER AIR TEMPS	IN	A	°F	D114CA	126	122	123
		B	°F	D115CA	120	122	122
	OUT	A	°F	D116CA	505	512	508
		B	°F	D117CA	499	497	496
PRIMARY AIR FAN INLET TEMPERATURES (Fan outlet temp. = Mill inlet temp)	A	°F	On Mills	315	345	345	340
	B	°F	On Mills	90	95	95	95
	C	°F	On Mills	320	325	330	315
	D	°F	On Mills	350	335	330	340

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

Test Number		Units	Log Code	49	49	49	49
Date		M-D-Y		10-15-80	10-15-80	10-15-80	10-15-80
Time		Military (24 hr)		1058	1554	1750	2113
PRIMARY AIR FAN OUTLET TEMPERATURES (Continued)		A	°F	NA			
		B	°F	NA			
		C	°F	NA			
		D	°F	NA			
PULVERIZER TEMPERATURES		IN	A	°F	NA		
			B	°F	NA		
			C	°F	NA		
			D	°F	NA		
		OUT	A	°F	D135	147	148
			B	°F	D136	103	105
			C	°F	D137	142	142
			D	°F	D138	152	154
FLUE GAS TEMPERATURES		SH OUTLET		°F	NA		
		RH OUTLET		°F	NA		
		ECONOMIZER OUTLET	A	°F	NA		
			B	°F	NA		
		MAIN AIR HTR.	IN	A	°F	D145CA	607
				B	°F	D146CA	609
			OUT	A	°F	D147CA	295
				B	°F	D148CA	300
		PRECIPITATOR OUTLET	A	°F	NA		
			B	°F	NA		
		I. D. FAN OUTLET	A	°F	NA		
			B	°F	NA		
		SCRUBBER OUTLET	A	°F	NA		
			B	°F	NA		
		STACK TEMP		°F	D199	171	171
WATER COIL AIR HEATER WATER TEMPERATURES		IN		°F	D107	319	300
			A	°F	D108	161	140
		OUT	B	°F	D109	129	128
ECONOMIZER FEEDWATER TEMPERATURE		IN		°F	F100CA	468	468
			A	°F	B226	-	-
		OUT	B	°F	B227	-	-
BOILER FEEDWATER PUMP SUCTION				°F	F136	368	368

MILL CREEK NO. 3

CONTROL ROOM BOARD DATA

(CONTINUED)

Test Number				Units	Log Code						
Date						49	49	49	49	AVG	
Time				M-D-Y		10-15-80	10-15-80	10-15-80	10-15-80	For Test	
				Military (24 hr)		1059	1559	1751	2120		
PRIMARY SH OUTLET STEAM TEMPERATURE			A	OF	B146	-	-	-	-		
			B	OF	B147	-	-	-	-		
PRIMARY SH STEAM AFTER SPRAY		IN	A	OF	B138	725	715	715	715		
			B	OF	B139	725	715	710	715		
		OUT	A	OF	B132	-	-	-	-	-	
			B	OF	B133	-	-	-	-	-	
SECONDARY SH STEAM OUTLET TEMP.				OF	B106	-	-	-	-		
REHEAT STEAM TEMP.	COLD IN		OF	B189CA	620	624	618	621			
	ATTEMPERATION SECTION STEAM TEMPERATURE	IN	A	OF	NA						
			B	OF	NA						
		OUT	A	OF	NA						
			B	OF	NA						
	HOT (OUT)		OF	B155	-	-	-	-			
HOT REHEAT TEMP. AT TURBINE				OF	B154	1000	998	993	996		
CALCULATED REHEAT SPRAY TEMP.				OF	B186	368	372	371	372		
MAIN STEAM TEMP.				OF	B102	1004	1004	1006	1004		
WINDBOX O ₂	A	%	D155	-	-	-	-	-			
	B	%	D156	-	-	-	-	-			
	AVG	%	NA								
BOILER EXIT GAS O ₂	A	%	NA								
	B	%	NA								
	AVG	%	D103	4.69	5.65	5.89	5.03	5.32			
SO ₂	ENTERING SCRUBBER		PPM	P186CA	2348	2514	2557	2774	2548		
	LEAVING SCRUBBER		PPM	P194CA	696	888	916	730			
FLUE GAS NO _x			PPM	P195	400.9	408.1	410.9		403		
FLUE GAS OPACITY	ELECTRONIC		%	D198	29.3	33.1	34.6				
	SMOKE READER		%	PSN		60					
STACK O ₂			%MCR	CR	60	70	68				
BOILER	HEAT-LOSS METHOD		%	A715	-	-	-				
EFFICIENCY	IN - OUT METHOD		%	A716	-	-	-				
GROSS UNIT HEAT RATE				Btu/KW·HR	A700	-	-	-			
HIGH PRESSURE FEEDWATER HEATERS	FW LEAVING No. 1		OF	F180	174	175	175	175			
	FW ENTERING No. 1		OF	F184	118	121	121	119			
	No. 1 HEATER DRAIN		OF	F183	176	176	176	176			
	STEAM TO No. 1 HTR		OF	F181	196	206	194	184			
	STEAM TO No. 1 HTR		OF	F182	7.41	7.46	7.45	7.44			
SH OUTLET LEG TC		HDR 1 LEG 12		OF	B402	-	-	-			
RH OUTLET LEG TC's	HDR 1 BOTT LEG		OF	B409	-	-	-				
	HDR 10 REAR LEG		OF	B428	-	-	-				

APPENDIX B

COAL AND ASH ANALYSIS

Mill Creek

March 1979 AS FIRED COAL ANALYSIS

DAY	SAMPLE	DATE REPORTED	AS RECEIVED			DRIED			ASH FREE
			MOISTURE	ASH	SULPHUR	BTU	SULPHUR	BTU	
1	7-1898	3-3-79	10.86	13.52	3.39	10804	15.33	3.84	12302
2	7-1899	3-13-79	11.32	12.36	4.14	10754	13.94	4.67	12127
3	7-1900	3-9-79	9.25	13.92	4.12	10810	15.34	4.53	11912
4	7-1901	3-9-79	10.13	13.38	3.39	10934	14.89	3.78	12156
5	7-1902	3-9-79	9.88	13.45	3.61	11045	14.93	4.01	12257
6	7-1903	3-13-79	9.08	14.01	3.56	10993	15.41	3.92	12090
7	7-1906	3-20-79	9.39	16.19	4.12	10700	17.87	4.54	11808
8	7-1907	3-17-79	9.03	14.83	3.64	10975	16.30	4.00	12065
9	7-1908	3-20-79	9.33	15.46	3.32	10739	17.05	3.66	11844
10									
11	7-1909	3-20-79	8.87	14.17	5.90	10656	15.55	6.47	11693
12									
13	7-1916	3-20-79	9.62	12.88	3.48	11117	14.25	3.85	12300
14	7-1920	3-20-79	9.31	15.00	3.23	10862	16.54	3.56	11977
15	7-1921	3-20-79	8.57	13.16	3.18	11324	14.39	3.48	12385
16	7-1922	3-23-79	8.49	15.79	3.86	10767	17.26	4.22	11766
17	7-1923	3-23-79	8.52	15.32	3.42	10902	16.75	3.74	11910
18	7-1924	3-23-79	8.11	14.87	3.98	10925	16.18	4.33	11889
19	7-1925	3-27-79	7.95	15.24	4.13	11018	16.56	4.49	11970
20	7-1926	3-27-79	8.80	12.70	4.33	11336	13.93	4.75	12430
21	7-1927	3-27-79	9.93	15.55	4.34	10767	17.15	4.79	11876
22	7-1928	3-29-79	12.78	19.40	3.46	9606	22.24	4.00	11014
23									
24	7-1929	3-29-79	9.35	11.15	3.39	11429	12.30	3.74	12608
25	7-1972	4-5-79	8.37	10.67	3.32	11707	11.64	3.47	12231
26	7-1933	4-3-79	10.14	17.35	3.51	10668	16.20	3.90	11872
27	7-1934	4-3-79	8.76	13.22	3.99	11190	14.49	4.38	12264
28	7-1935	4-5-79	11.76	13.41	2.64	10682	15.19	3.00	12105
29	7-1936	4-5-79	9.44	14.86	3.39	10831	16.41	3.74	11960
30	7-1937	4-5-79	9.23	14.84	4.02	10857	16.35	4.43	11960
31	7-1938	4-5-79	9.99	14.81	3.79	10757	16.46	4.21	11952
MONTHLY									
AVERAGE			9.49	14.34	3.74	10898	15.75	4.13	12027
									14275

LOUISVILLE GAS & ELECTRIC
FPGD COMBUSTION SYSTEM

Sample No.	C-15075		C-15076	
Description	Coal 3-21-79		Coal 3-23-79	
Basis —————>	As Received	Dry	As Received	Dry
Total Moisture, %	7.3	—	9.0	—
PROXIMATE ANALYSIS, %				
Moisture	7.3	—	9.0	—
Volatile Matter	28.4	30.6	30.4	33.4
Fixed Carbon	47.8	51.6	41.1	45.2
Ash	16.5	17.8	19.5	21.4
Gross Heating Value				
Btu per lb	10590	11420	9960	10940
Btu per lb. (M&A Free)	—	13900	—	13920
ULTIMATE ANALYSIS, %				
Moisture	7.3	—	9.0	—
Carbon	58.7	63.3	56.6	62.2
Hydrogen	4.1	4.5	3.8	4.2
Nitrogen	1.13	1.22	1.06	1.17
Sulfur	4.6	5.0	3.1	3.5
Ash	16.5	17.8	19.5	21.4
Oxygen (Difference)	7.67	8.18	6.94	7.53
Total	100.00	100.00	100.00	100.00
Nitrogen lb/10 ⁶ Btu	1.07		1.06	

MILL CREEK NO. 3 COAL
SAMPLE NO. 001933

	Analyzed	Dry	DAF	DMMF	As Rec'd							
Moisture	2.01				8.62							
Ash	17.41	17.77		21.10								
SO ₃ Free Ash	16.70	17.04										
Carb-hyd Residue	16.59	16.93										
Volatile Matter	36.36	37.11	45.12	42.92								
Fixed Carbon	44.22	45.12	54.88	57.08								
Btu	11632.	11871.	14436.	14861.								
Carbon	64.36	65.68	79.87	83.04								
Hydrogen	4.42	4.51	5.48	5.53								
Nitrogen	1.10	1.12	1.37	1.42								
Oxygen (Diff-xH ₂ O, Cl)	6.74	6.88	8.37	8.51								
Chlorine	.03	.03	.03	.03								
Sulfur, Total (LECO)	3.96	4.04	4.92									
Pyritic	2.72	2.78										
Sulfate	0.09	0.09										
Organic DF/ES	1.16	1.18	1.43	1.49								
Sulfur, Eschka												
Carbon Dioxide	0.55	0.56	0.69	0.71								
Undetermined	6.74											
Fe (HCL soluble)	0.00	0.00										
Fe (HNO ₃ soluble)	2.43	2.48										
Ash Alk, (as % Na ₂ O)	0.39	0.40										
ASH FUSION	Reducing Atmosphere				Oxidizing Atmosphere							
	ID	H=W	H=W/2	Fluid	ID	H=W	H=W/2	Fluid				
Temp. Deg. F	1980	2030	2050	2080	2300	2360	2435	2480				
ELEMENTAL ANALYSIS OF DRY ASH (wt %)												
	P ₂ O ₅	SiO ₃	Fe ₂ O ₃	Al ₂ O ₃	TiO ₃	CaO	MgO	SO ₃	K ₂ O	NaO ₂	TOTAL	DIFF
	0.35	46.99	21.08	16.86	0.94	4.42	1.19	4.10	2.71	0.48	99.13	0.87
w/o SO ₃	0.37	46.45	22.18	17.75	0.99	4.66	1.25	-	2.85	0.50		
QUALITY FACTORS:	B/A Ratio: 0.46		Slag Index: 1.86		Foul Index: 0.22							
	Dol. Ratio: 0.19		Fe ₂ O ₃ /CaO: 4.76		S1/Al: 2.79							
	SI. Value: 0.64		CVT: 2280.0		P: 0.00							
MOTT-SPOONER:	14908											
TIGER Van Sample: Mill Creek No. 3 Coal, October 1980. From first SO ₂ -SO ₃ test.												
Test sample caught at 11:00 am, Friday 10-10-80.												

TIGER VAN MRD-80-064
SAMPLE NO. 002991

	Analyzed	Dry	DAF	DMMF								
Moisture	3.56											
Ash	12.61	13.07		15.43								
SO ₃ Free Ash	12.08	12.53										
Carb-hyd Residue	12.84	13.31										
Volatile Matter	37.41	38.80	44.63	43.17								
Fixed Carbon	46.41	48.13	55.37	56.83								
Btu	12134.	12582.	14475.	14775.								
Carbon	66.84	69.31	79.73	81.80								
Hydrogen	4.58	4.75	5.46	5.49								
Nitrogen	1.49	1.55	1.78	1.83								
Oxygen (Diff-xH ₂ O, Cl)	7.04	7.30	8.40	8.22								
Chlorine	0.01	0.01	0.01	0.01								
Sulfur, Total (LECO)	3.88	4.03	4.63									
Pyritic	1.64	1.70										
Sulfate	0.07	0.07										
Organic DF/ES	2.17	2.26	2.59	2.67								
Sulfur, Eschka												
Carbon Dioxide	0.44	0.46	0.53	0.54								
Undetermined	7.04											
Fe (HCl soluble)	0.00	0.00										
Fd (HNO ₃ soluble)	1.45	1.51										
Ash Alk, (as % Na ₂ O)	0.27	0.28										
ELEMENTAL ANALYSIS OF DRY ASH (wt %)												
	P ₂ O ₅	SiO ₃	Fe ₂ O ₃	Al ₂ O ₃	TiO ₃	CaO	MgO	SO ₃	K ₂ O	NaO ₂	TOTAL	DIFF
w/ SO ₃	0.23	47.05	19.21	17.48	0.99	5.16	1.04	4.15	2.55	0.43	98.28	1.72
w/o SO ₃	0.25	49.98	20.40	18.57	1.05	5.48	1.10	-	2.71	0.46		
QUALITY FACTORS:		B/A Ratio: 0.43		Slag Index:		1.75		Foul Index:		0.19		
		Dol. Ratio: 0.22		Fe ₂ O ₃ /CaO:		3.72		Si/Al:		2.69		
		SI. Value: 0.65		CVT:				P:		0.00		
MOTT-SPOONER:		14765.										
TIGER Van Sample: From coal from belt feeding the hoppers. LG&E Mill Creek												
No. 3. REHD's sample No. MRD-80-064 Level 1 Test. October 15, 1980.												

TIGER VAN MRD-80-064

ANALYTICAL RESEARCH LABORATORY
BAYTOWN R&D

ICPES ANALYSIS IN PPM

Moisture = 0.64%
Ash = 13.31%

Sample: MP622 LAR 724644				Dilution: 864.6	
Ag <4.41	Al 11200	As <18.2	B <0.519	Ba 57.6	Be 5.53
Ca 5360	Cd 27	Co 11.1	Cr 20.3	Cu 18.2	Fe 17100
K 2160	Li 7.71	Mg 602	Mn 43.6	Mo (18.2)	Na 462
Ni (24.8)	P 171	Pb 43.5	Pt <65.7	Sb (31.1)	Se 110
Si 35000.	Sn (21)	Sr 17.5	Ti 295	Tl (8.47)	U 100
V 31	W <51.9	Zn 112			
Total Elements = 73100					
*value out of range, need further dilution.					
<element not detected					
()value may not be significant					

DIAGNOSTICS: CONCENTRATION AS % OF UNCORRECTED (values nearer 100 usually are more reliable)					
81	100	-11	100	100	29
100	96	93	100	99	100
100	100	100	93	-74	100
99	91	129	67	32	-60
100	117	100	100	28	55
87	38	100			
ICPWFL (22 0 1371)					

Tiger Van Sample: Coal from belt fielding the hoppers, LG&E Mill Creek No. 3.
REHD'S Sample No. MRD-80-064. Level Test. October 15, 1980.

BARD's Sample No. 002991

TIGER VAN MRD-80-064
BARD'S SAMPLE NO. 002992

	Analyzed	Dry	DAF	DMMF	
Moisture	0.19				
Ash	97.20	97.39			
SO ₃ Free Ash	95.61	95.79			
Carb-hyd Residue	96.92	97.10			
Volatile Matter					
Fixed Carbon					
Btu					
Carbon	1.77	1.77	67.85		
Hydrogen	0.05	0.05	1.76		
Nitrogen					
Oxygen (Diff-xH ₂ O, Cl)					
Chlorine					
Sulfur, Total (LECO)					
Pyritic					
Sulfate					
Organic DF/ES					
Sulfur, Eschka					
Carbon Dioxide	0.16	0.16		6.13	
Undetermined	0.79				
Fe (HCl soluble)					
Fe (HNO ₃ soluble)					
Ash Alk, (as % Na ₂ O)	2.21	2.22			
Solubles % Dry Ash	H ₂ O: Na = 0.02	K = 0.08	Ca = 0.78		
	HCl: Na = 0.10	K = 0.81	Ca = 0.78		
ASH FUSION	Reducing Atmosphere				Oxidizing Atmosphere
	ID	H=W	H=W/2	Fluid	ID H=W H=W/2 Fluid
Temp. Deg. F	1980	2030	2050	2080	2300 2360 2435 2480
ELEMENTAL ANALYSIS OF DRY ASH (wt %)					
	P ₂ O ₅	SiO ₃	Fe ₂ O ₃	Al ₂ O ₃	TiO ₃ CaO MgO SO ₃ K ₂ O NaO ₂ TOTAL DIFF
w/ SO ₃	0.40	46.64	20.30	18.72	0.96 5.51 1.17 1.64 2.81 0.43 98.58 1.42
w/o SO ₃	0.42	48.11	20.94	19.31	0.99 5.68 1.21 - 2.90 0.44
QUALITY FACTORS:	B/A Ratio: 0.46		Slag Index:		Foul Index: 0.19
	Dol. Ratio: 0.22		Fe ₂ O ₃ /CaO: 3.68		Si/Al: 2.49
	SI. Value: 0.63		CVT:		
MOTT-SPOONER:	14908				

Tiger Van Sample. Fly ash from precipitator. LG&E Mill Creek No. 3.
REHD's Sample No. MRD-80-065. Level 1 Test. October 15, 1980.

TIGERS VAN MRD-80-065

ANALYTICAL RESEARCH LABORATORY
BAYTOWN R&D

Moisture = 0.10%
Ash = 97.50%

ICPES ANALYSIS IN PPM

Sample: MP621 LAR 724644					Dilution: 870.8
Ag <4.44	Al 89500.	As (24.6)	B <0.522	Ba 552	Be <1.04
Ca 33200	Cd 27.1	Co (8.02)	Cr 101	Cu 91.5	Fe 124000.
K 19500	Li 67.2	Mg 5460	Mn 336	Mo 88.7	Na 2870
Ni 119	P 1690	Pb <18.3	Pt <66.2	Sb (78.7)	Se 354
Si 200000.	Sn 67	Sr 183	Ti 4810	Tl 40.1	U 214
V 498	W (86.4)	Zn 719			
Total Elements = 485000.					
* value out of range, need further dilution.					
< element not detected					
() value may not be significant					

DIAGNOSTICS: CONCENTRATION AS % OF UNCORRECTED (values nearer 100 usually are more reliable)					
49	99*	18	101	100	-1
100*	65	36	100	97	100
100	100	100	93	-39	100
104	94	11	-121	17	-19
97	416	100	100	-19	26
93	21	100			
*low sens channel					
ICPWF (21 7.06 -9)					

Tiger Van Sample: Fly ash from precipitator. LG&E Mill Creek No. 3. REHD's
Sample No. MRD-80-065. Level 1 Test. October 15, 1980.

BARD's Sample No. 002992

APPENDIX C

FLUE GAS DATA EXAMPLE

Due to the large volume of flue gas data, it is impractical to present all of it here. The data have been summarized in Table B-III-1, and the purpose of this appendix is to present an example of the detail upon which that summary is based. Field data from Test No. 27 (a baseline test at 400 MW) are presented as an example of the detailed flue gas data kept for each test.

The first table is "as-measured" data (resulting from a computerized linearization of the raw data). Following the "as-measured" table, is a table of results normalized to a standard dilution (i.e.: 3% oxygen). All data are on a dry basis and have been adjusted to factor out leaks.

The sampling location was between the economizer and air heater.

LG&E MILL CREEK UNIT NO. 3

FLUE GAS ANALYSIS "AS MEASURED" (DRY)

TEST NO. 27

PROBE NUMBER	O ₂ (%)	NO _x (Chemi) (ppm)	NO (Chemi) (ppm)	NO (NDIR) (ppm)	CO (ppm)	CO ₂ (%)	Reading Number*
1	4.80	380.	375.	390.	16.	13.70	First Readings
2	5.00	375.	350.	374.	16.	13.70	
3	4.50	370.	360.	374.	18.	13.95	
4	3.90	355.	350.	374.	18.	14.20	
1	4.70	370.	370.	293.	16.	13.45	Second Readings
2	4.80	370.	360.	390.	16.	13.21	
3	4.70	350.	350.	358.	16.	13.70	
4	3.60	350.	350.	374.	18.	14.46	
1	5.00	380.	375.	390.	16.	13.45	Third Readings
2	4.60	380.	370.	390.	16.	13.70	
3	4.60	360.	350.	375.	16.	13.95	
4	3.20	360.	355.	374.	20.	14.71	

*Gas from each probe (in turn) is routed to the analyzers, and the composition of the gas (each analyzer's output) is recorded. This process is repeated, switching probes every two minutes until each probe is analyzed three times or more.

LG&E MILL CREEK UNIT NO. 3

FLUE GAS ANALYSIS "CORRECTED TO 3% O₂" (DRY)

TEST NO. 27

PROBE NUMBER	O ₂ (%)	NO _x (Chem.) (ppm)	NO (Chem.) (ppm)	NO (NDIR) (ppm)	CO (ppm)	CO ₂ (%)	Reading Number*
1	4.80	422.	417.	434.	18.	15.22	First Readings
2	5.00	422.	394.	421.	18.	15.41	
3	4.50	404.	393.	408.	20.	15.22	
4	3.90	374.	368.	394.	19.	14.95	
1	4.70	409.	409.	323.	18.	14.86	Second Readings
2	4.80	411.	400.	434.	18.	14.68	
3	4.70	387.	387.	395.	18.	15.13	
4	3.60	362.	362.	387.	19.	14.95	
1	5.00	428.	422.	439.	18.	15.14	Third Readings
2	4.60	417.	406.	428.	18.	15.04	
3	4.60	395.	384.	410.	18.	15.31	
4	3.20	364.	359.	378.	20.	14.88	
1	4.83	419.	416.	399.	18.	15.07	Averages
2	4.80	417.	400.	428.	18.	15.04	
3	4.60	395.	388.	404.	18.	15.22	
4	3.57	367.	363.	386.	19.	14.93	
1&2	4.82	418.	408.	413.	18.	15.06	
3&4	4.08	381.	375.	395.	19.	15.07	
1,2,3&4	4.45	399.	392.	404.	18.	15.07	

APPENDIX D
CONVERSION FACTORS
F FACTORS
AND
SAMPLE CALCULATIONS

CONVERSION FACTORS

English and Metric Units to SI Units

To Obtain	From	Multiply By	To Obtain ng/J for	Multiply Concentrations (in ppm dry at 3% O ₂) by
ng/J	1b/MBtu	430		
ng/J	g/MCal	239		
GJ hr ⁻¹ m ⁻²	MBH**/ft ²	11,356		
GJ hr ⁻¹ m ⁻³	MBH**/ft ³	37,257		
GJ/hr	10 ³ lb/hr* or MBH	1,055		
MW	10 ³ lb/hr* or MBH	0.293		
m	ft	0.3048		
cm	in	2.54		
cm	mls	0.00254		
m ²	ft ²	0.0929		
m ³	ft ³	0.02832		
Kg	lb	0.4536		
°Kelvin	°Rankin	5/9		
°Celsius	°Fahrenheit	$t_c = (5/9)(t_F - 32)$		
°Kelvin	°Fahrenheit	$t_k = ((5/9)(t_F - 32)) + 273$		
°Kelvin	°Celsius	$t_k = t_c + 273$		
Pa	psig	$P_{pa} = (P_{sig} + 14.7)(6895)$		
Pa	psia	$P_{pa} = (P_{psia})(6895)$		
Pa	iwg*** (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$		
Pa	in Hg	3385		
in H ₂ O	in Hg	13.6		
atm	in Hg	1/760		
mmHg	in Hg	25.4		
psi	in Hg	0.491		

Natural Gas Fuel	
CO	0.310
HC	0.177
NO _x , NO, or NO ₂ (As Equivalent NO ₂)	0.510
SO _x (SO ₂)	0.709

Oil Fuel	
CO	0.341
HC	0.195
NO _x , NO, or NO ₂ (As Equivalent NO ₂)	0.561
SO _x (SO ₂)	0.780

Coal Fuel	
CO	0.372
HC	0.213
NO	0.395
NO _x , NO, or NO ₂ (As Equivalent NO ₂)	0.589
SO _x (SO ₂)	0.850

*1b/hr of equivalent saturated steam. (For water, the heat of the liquid to gas phase change is about 10³ Btu/pound.)
 **10⁶ Btu/hr
 ***The symbols iwg and in H₂O g are used interchangeably.

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10 ⁶ Btu	GJ	0.948
MBH/ft ²	GJ·hr ⁻¹ m ⁻²	0.08806
MBH**/ft ³	GJ·hr ⁻¹ m ⁻³	0.02684
Btu	gm cal	3.9685 x 10 ⁻³
10 ³ lb/hr* or MBH	GJ/hr	0.948
10 ³ lb/hr* or MBH	MW	3.413
lb/MBtu	ng/J	0.00233
ft	m	3.281
in	cm	0.3937
mils	cm	393.7
ft ²	m ²	10.764
ft ³	m ³	35.314
lb	Kg	2.205
°Rankin	°Kelvin	1.80
°Fahrenheit	°Celsius	$t_F = 9/5(t_C) + 32$
°Fahrenheit	°Kelvin	$t_F = 1.8 T_K - 460$
°Rankin	°Fahrenheit	$t_R = t_F + 460$
psig	Pa	$P_{psig} = (P_{Pa})(0.0001450) - 14.7$
psia	Pa	$P_{psia} = (P_{Pa})(0.0001450)$
1wg*** (39.2°F)	Pa	$P_{1wg} = (P_{Pa})(0.004014)$
in Hg	in H ₂ O	0.00295
in Hg	atm	1/13.6
in Hg	mm Hg	760
in Hg	psi	1/25.4
in Hg		2.036

*lb/hr of equivalent saturated steam. (For water, the heat of the liquid to gas phase change is about 10³ Btu/pound.)
 **10⁶ Btu/hr
 ***The symbols 1wg and in H₂O g are used interchangeably.

To Obtain ppm (dry) at 3% O ₂ for	Multiply Flow Concentrations in ng/J, by
---	--

Natural Gas Fuel	
CO	3.23
HC	5.65
NO _x , NO, or NO ₂ (As Equivalent NO ₂)	1.96
SO _x (SO ₂)	1.41

Oil Fuel	
CO	2.93
HC	5.13
NO _x , NO, or NO ₂ (As Equivalent NO ₂)	1.78
SO _x (SO ₂)	1.28

Coal Fuel	
CO	2.69
HC	4.69
NO	2.53
NO _x , NO, or NO ₂ (As Equivalent NO ₂)	1.71
SO _x (SO ₂)	1.18

CONVERSION FACTORS

ENGLISH TO SI UNITS

To Convert From	To	Multiply By*
Btu	Gigajoule, GJ	1.055 056 E-06
MBtu/h	Megawatt, MW	0.293 000 E-01
Btu/lb	Gigajoule/kilogram, GJ/kg	2.326 000 E-06
Btu/lb	Calories/gram, cal/g	5.559 273 E-01
Pounds/square inch	Megapascal, MPa	6.894 757 E-03
	Kilopascal, kPa	6.894 757 E+00
Pounds/hour, lb/h	Kilogram/hour, kg/h	4.535 934 E-01
Pounds/hour, lb/h	Metric tons/hour, t/h	4.535 925 E-04
Tons (short)	Metric tons, t	9.071 847 E-01
Pounds, lb	Kilogram, kg	4.535 924 E-01
Feet, ft	Metre, m	3.048 000 E-01
Square Feet, ft ²	Metres ² , m ²	9.290 304 E-02
Inches, in.	Centimetres, cm	2.540 000 E-00
Inches, in.	Metre, m	2.540 000 E-02
Grains/cubic foot	Milligrams/metre ³ , mg/m ³	2.288 351 E-01
Cubic feet, ft ³	Metre ³ , m ³	2.831 685 E-02
	Decimetre ³ , dm ³	2.831 685 E+01
Gallons	Metres ³ , m ³	3.785 412 E-03
	Decimetre ³ , dm ³	3.785 412 E+00

*Numbers expressed in power-of-ten notation using E + xx to indicate the power of ten. For example:

$$1.055\ 056\ E-06 = 1.055\ 056 \times 10^{-6} = .000001055056$$

CONVERSION FACTORS FOR NO_x AND SO₂ EMISSIONS
FROM BITUMINOUS COAL COMBUSTION

To Convert From	To	For NO _x * Emissions (as NO ₂) Multiply By	For SO ₂ ** Emissions Multiply By
ppm at 3% O ₂ Dry	$\frac{g}{DSCM}$ at 3% O ₂	0.0019134	0.001662
$\frac{g}{DSCM}$ at 3% O ₂	$\frac{g}{DSCM}$ at 0% O ₂	1.167	1.167
$\frac{g}{DSCM}$ at 0% O ₂	$\frac{g}{DSCF}$ at 0% O ₂	0.02832	0.02832
$\frac{g}{DSCF}$ at 0% O ₂	$\frac{g}{MBtu}$	9,820	9,820
$\frac{g}{MBtu}$	$\frac{lb}{MBtu}$	0.002205	0.002205
$\frac{lb}{MBtu}$	$\frac{ng}{J}$	430	430

ppm at 3% O ₂ (dry)	lb/MBtu	0.001369	0.00190
ppm at 3% O ₂ (dry)	ng/J	0.5888	0.819

*In these calculations, consistent with EPA guidelines, NO_x is treated as 100% NO₂ (molecular weight = 46 lb/lb-Mole) since NO_x (as NO, MW = 30) is eventually converted in the atmosphere to NO₂. Actual flue gas measurements, however, indicate that NO_x has a composition of about 5% NO₂ and 95% NO (MW = 30.8).

**Typically SO_x emissions are >99% SO₂, and 1% SO₃.
SO₂ molecular weight = 64.0 lb/lb mole.

DEFINITION OF STANDARD CONDITIONS, AND
LIST OF VOLUME ABBREVIATIONS

STANDARD CONDITIONS

EPA defines standard temperature and pressure (STP) as 20°C and 1 atm.

- o 20°C = 293°K = 68°F = 528°R
- o 1 atm = 760 mmHg = 29.92 in Hg =
14.7 psia = 406.8 in H₂O = 101.3 kPa

VOLUME ABBREVIATIONS

m ³	=	Cubic meters
SCM	=	Standard cubic meters
ACM	=	Actual cubic meters
WSCM	=	Standard cubic meters (wet basis)
DSCM	=	Standard cubic meters (dry basis)

ft ³	=	Cubic feet
SCF	=	Standard cubic feet
ACF	=	Actual cubic feet
WSCF	=	Standard cubic feet (wet basis)
DSCF	=	Standard cubic feet (dry basis)

SAMPLE CALCULATIONS

$$\left(\begin{array}{c} \text{Concentration} \\ \text{on Dry Basis} \end{array} \right) = \left(\begin{array}{c} \text{Concentration} \\ \text{on Wet Basis} \end{array} \right) \left(\frac{1}{1 - (\text{moisture fraction})} \right)$$

Example: If SO₂ has concentration 2.00 g/WSCF* in a gas containing 10% H₂O vapor by volume, then

$$\left(\begin{array}{c} \text{Concentration} \\ \text{on Dry Basis} \end{array} \right) = \left(2.0 \frac{\text{g}}{\text{ft}^3} \right) \left(\frac{1}{1 - 0.10} \right) = 2.22 \text{ g/DSCF}$$

$$^{**} \left(\begin{array}{c} \text{Concentration Corrected to} \\ \text{X\% O}_2 \text{ Dilution} \end{array} \right) = \left(\begin{array}{c} \text{Actually Measured} \\ \text{Concentration at} \\ \text{Actual O}_2 \\ \text{Dilution (Y\% O}_2 \end{array} \right) \left(\frac{21-X}{21-Y} \right)$$

Example: 400 ppm NO_x at 4% O₂ = 423.5 ppm NO_x at 3% O₂.

$$^{**} \left(\begin{array}{c} \text{Flow Rate Corrected} \\ \text{to X\% O}_2 \end{array} \right) = \left(\begin{array}{c} \text{Flow Rate At} \\ \text{Y\% O}_2 \end{array} \right) \left(\frac{21-Y}{21-X} \right)$$

Example: A gas having flow rate 10 ft³/min at 4% O₂ would have flow rate 9.444 at 3% O₂. (Assuming all other conditions: moisture content, temp, pres...remain unchanged.)

$$\text{ppm} = \left(\begin{array}{c} \text{Concentration by weight (g/m}^3 \text{)} \\ \text{at temperature T (}^\circ\text{K)} \\ \text{and pressure P (Atm)} \\ \left(\begin{array}{c} \text{molecular: } \frac{\text{g}}{\text{g Mole}} \\ \text{weight} \end{array} \right) \end{array} \right) \left(82.05^{***} \right) \left(\frac{T (^\circ\text{K})}{P (\text{Atm})} \right)$$

*WSCF = Wet Standard Cubic Foot (68°F, 1 Atm).

**These formulas assume that, for the purpose of dilution corrections, oxygen can enter or leave the system only in the form of air. That is: for every volume of O₂ crossing the system boundary, 3.76 volumes of inert gas (nitrogen) also cross the boundry. (Air is 21% O₂.)

***82.05 is the value of "R," the universal gas constant, and has units of

$$\frac{\text{cm}^3 \text{ Atm}}{\text{gMole } ^\circ\text{K}}$$

Example: If SO₃ (molecular weight = 80 g/g·mole) has a concentration (by weight) of 300 mg/DSCM,* then its concentration in parts per million is:

$$\text{ppm} = \left(\frac{0.300}{80} \right) \left(82.05 \times \frac{293}{1} \right) = 90.15 \text{ ppm (Dry)}$$

Since the original concentration was given on a dry basis, the converted result is also still on a dry basis.

Of course, the above equation may be rearranged to facilitate conversion from ppm to grams/meter³ at any temperature and pressure:

$$\left(\begin{array}{l} \text{Concentration by weight (g/m}^3\text{)} \\ \text{At Temperature T} \dots\dots (\text{°K}) \\ \text{and Pressure P} \dots\dots (\text{Atm}) \end{array} \right) = \left(\begin{array}{l} (\text{ppm}) \left(\begin{array}{l} \text{Molecular wt} \\ \text{of specie} \\ \text{of interest} \\ \text{(g/gMole)} \end{array} \right) (P(\text{Atm})) \\ \hline 82.05 T(\text{°K}) \end{array} \right)$$

(The reader should note that this is valid for ordinarily encountered concentrations where the volume percent of the pollutant is small. That is: <10,000 ppm)

CONVERTING TO THE STANDARD UNIT OF EMISSION: POUNDS/MBtu

The "F" factor method can be used to convert the emission rate to the standard units of pounds per MBtu through of the following equation:***

$$\left(\frac{\text{Pounds}}{\text{MBtu}} \right) = \left(\frac{\text{Pounds}}{\text{DSCF}} \right) (F_d) \left(\frac{21}{21 - \%O_2} \right)$$

Where: %O₂ = Oxygen concentration at which the value marked by the double asterisk is valid.

F_d = The "F" factor for the fuel being burned. It has units of DSCF/MBtu (at 0% O₂) and as such, is readily available in published F factor tables.

*DSCM = dry standard cubic meter. (T = 293°K, and, P = 1 Atm.)

**Obtained by conversion of the formula for "concentration by weight" listed on the preceding page.

***G. J. Aldina, J. A. Jahnke, "Source Sampling for Particulate Pollutants" pg. 140, manual for course No. 450 of EPA's Air Pollution Training Institute. Prepared by Northrup Services Inc., under EPA contract No. 68-02-2374, January 1978.

For bituminous coal, the EPA-APTI training manual (referenced on the bottom of the previous page) gives:

$$F_d = 9820 \frac{\text{DSCF}}{\text{MBtu}} \quad (\text{at } 0\% \text{ O}_2)$$

This assumes complete combustion, and no excess oxygen - an assumption already factored into the previous equation.

Rather than using the tabulated value for F_d , the value of F_d may be calculated from fuel analysis according to the following formula (given on pg 145 of the above referenced manual):

$$F_d = \frac{10^6 (3.64\% \text{ H} + 1.53\% \text{ C} + 0.57\% \text{ S} + 0.14\% \text{ N} - 0.46\% \text{ O})}{\text{High Heating Value: Btu/lb}}$$

For example, plugging in values from Exxon's coal analysis from the Level 1 test (October 15, 1980, Appendix B) gives:

$$\begin{aligned} F_d &= \frac{10^6 [(3.64)(4.75) + (1.53)(69.3) + (0.57)(4.03) + (0.14)(1.55) - (0.46)(7.3)]}{12,582} \\ &= 9734 \frac{\text{DSCF}}{\text{MBtu}} \quad (\text{at } 0\% \text{ O}_2) \end{aligned}$$

This (9734) agrees fairly well with the published value (9820). However, before this formula for converting to standard emission units can be used, the concentration of the pollutant specie of interest must first be expressed in units of $\frac{\text{Pounds}}{\text{DSCF}}$ at any known oxygen concentration.

As a first example, let us consider one of the GC results. This will be a good exercise since these are initially expressed in the worst possible units for use in the above equation, and must undergo several conversions in order to get them into appropriate units.

Most other emissions are already expressed in terms that are intermediate in the following example.

Each conversion uses one of the formulas (in original or rearranged form) given at the beginning of this appendix.

EXAMPLE No. 1:

GC results are reported as either "%" or "ppm" on a wet basis (assume 10% H₂O) and at the duct's actual O₂ concentration. (4.8% O₂ - Dry Basis - from van readings - Appendix C.)

o Converting to dry basis:

The H₂ reading, for example, is given as 0.005% (50 ppm) by volume. Correcting this to a dry basis is done by factoring out the 0.1 fraction of water:

$$\begin{aligned}(\text{ppm H}_2, \text{ Dry Basis}) &= (\text{ppm H}_2, \text{ Wet Basis}) / (1 - 0.1) \\ &= 55.6 \text{ ppm H}_2 \text{ (Dry Basis at 4.8\% O}_2\text{)}.\end{aligned}$$

o Converting to 3% O₂:

Correcting the dry basis from 4.8% O₂ to 3% O₂ is done as follows:

$$\left(\frac{18}{21 - 4.8} \right) (55.6) = 61.8 \text{ ppm H}_2 \text{ at 3\% O}_2, \text{ Dry Basis}$$

o Converting to units of mass or weight at STP:

Converting to weight units at standard conditions is done as follows:

$$\begin{aligned}\frac{\text{g}}{\text{m}^3} &= (\text{ppm}) \left(\frac{\text{g}}{\text{g Mole}} \right) / \left[(82.05) \left(\frac{T(^{\circ}\text{K})}{P(\text{Atm})} \right) \right] \\ &= (61.8)(2) / \left[(82.05) \left(\frac{293}{1} \right) \right] \\ &= 0.00507 \text{ g/m}^3 \left\{ \begin{array}{l} \text{Since the "ppm" concentration fed into the} \\ \text{formula was on a dry basis at 3 vol \% O}_2, \\ \text{this H}_2 \text{ concentration is still on a dry} \\ \text{basis at 3\% (by volume) O}_2. \end{array} \right. \\ &= 0.00014 \text{ g/DSCF} \\ &= 3.17 \times 10^{-7} \text{ Pounds H}_2\text{/DSCF (at 3\% O}_2\text{)}\end{aligned}$$

o Converting to standard units (weight per heat input):

As explained a few paragraphs earlier...

$$\left(\frac{\text{Pounds}}{\text{MBtu}} \right) = \left(\frac{\text{Pounds}}{\text{DSCF}} \right) (F_d) \left(\frac{21}{21 - \% \text{ O}_2} \right)$$

$$= (3.17 \times 10^{-7})(9734*) \left(\frac{21}{21 - 3} \right)$$

$$= 0.0036 \frac{\text{Pounds of H}_2}{10^6 \text{ Btu}}$$

EXAMPLE No. 2 (SASS):

SASS results arrive initially in terms of "weight per total sample." For example, the chemist may have found that the total sample contained "X" grams of particulate. Using the values given on the second table in Appendix H (Table GH-2), one finds that, for this SASS run, X/949 is the concentration expressed on a mass per volume of gas basis. Specifically, X/949 is the weight per DSCF at standard dry conditions (0.0% H₂O, 5.7% O₂, 68°F, 29.92 in. Hg) and has units of g/ft³.

Correcting to 0.0% O₂ gives

$$\left(\frac{X}{949} \right) \left(\frac{21}{21 - 5.7} \right) = (0.001446)(X)$$

This expression has units of $\frac{g}{\text{DSCF}}$ (at 0% O₂).

Multiplying by the "F" factor gives

$$\left(0.001446 \cdot X \frac{g}{\text{DSCF (at 0\% O}_2\text{)}} \right) \left(9734* \frac{\text{DSCF (at 0\% O}_2\text{)}}{\text{MBtu}} \right) = 14.21 \cdot X \frac{g}{\text{MBtu}}$$

In other words: To convert any of these SASS results from "weight per total sample" to "weight per MBtu," simply multiply by 14.21**. Similarly, for metric units (weight per Joule), the factor is 1.35×10^{-8} .

EXAMPLE No. 3 (SO_x):

Sample Calculation for SO_x

$$\begin{aligned} \textcircled{A} \left(\begin{array}{c} \text{Number of} \\ \text{moles of} \\ \text{SO}_3 \text{ sampled} \end{array} \right) &= \frac{\left(\begin{array}{c} \text{Volume of} \\ \text{Titrant} \\ \text{in liters} \end{array} \right) \left(\begin{array}{c} \text{Normality} \\ \text{of} \\ \text{Titrant} \end{array} \right) / 2}{\left(\begin{array}{c} \text{Fraction of impinger} \\ \text{solution titrated} \end{array} \right)} \\ &= \frac{(0.001)(0.01)/2}{(1/5)} = 0.000025 \text{ g}\cdot\text{moles} \end{aligned}$$

At a molecular weight (MW) of $80 \frac{g}{\text{g}\cdot\text{mole}}$, this is the same as saying that the sample contained 0.002 g, or 20 mg of SO₃.

*Calculated earlier in this appendix.

**1/14.21 (or 0.0704) is the number of MBtu's of coal that had to be burned to produce the amount of flue gas sampled during this test.

$$\begin{aligned}
 \textcircled{B.} \quad \text{mg/DSCM}^* &= \frac{\left(\begin{array}{c} \text{weight} \\ \text{collected} \end{array} \right)}{\left(\begin{array}{c} \text{volume} \\ \text{shown on} \\ \text{gas meter} \end{array} \right) \left(\frac{T_{\text{std}}}{T_{\text{meter}}} \right) \left(\frac{P_{\text{meter}}}{P_{\text{standard}}} \right)} \\
 &= \frac{2.0 \text{ mg}}{\left(20 \text{ liters}/1000 \frac{\text{L}}{\text{m}^3} \right) \left(\frac{528^{\circ}\text{R}}{546^{\circ}\text{R}} \right) \left(\frac{29.5 \text{ in Hg}}{29.92 \text{ in Hg}} \right)} = 103 \frac{\text{mg SO}_3}{\text{DSCM}_{\text{total sample}}}
 \end{aligned}$$

$$\begin{aligned}
 \textcircled{C.} \quad \text{ppm} &= \frac{(\text{DSCM SO}_3 \text{ (or SO}_2\text{)}) (1,000,000)}{\text{DSCM}_{\text{total sample}}} \\
 &= \frac{\left(\text{moles}_{\text{SO}_3} \right) \left(\frac{R^{**} T_{\text{std}}}{P_{\text{std}}} \right) (1,000,000)}{(\text{DSCM}_{\text{total sample}})} \\
 &= \left(\frac{\text{grams}_{\text{SO}_3}}{\text{DSCM}_{\text{total sample}}} \right) \left(\frac{\text{molecular weight}_{\text{SO}_3}}{\text{gmole } ^{\circ}\text{R}} \right) \left(\frac{0.0000456 \text{ m}^3 \text{ Atm}}{\text{gmole } ^{\circ}\text{R}} \right) (528^{\circ}\text{R}) (1,000,000) \\
 &= \left(0.103 \frac{\text{g}}{\text{DSCM}} \right) \left(80 \frac{\text{g}}{\text{gmole}} \right) \left(0.0241 \frac{\text{DSCM}}{\text{gmole}} \right) (1,000,000) \\
 &= 31 \text{ parts per million (ppm)}
 \end{aligned}$$

$$\begin{aligned}
 \textcircled{D.} \quad \frac{\text{pounds}}{\text{MBtu}} &= \left(\frac{\text{pounds}}{\text{DSCF}} \right) (F_d^{***}) \left(\frac{21}{21 - \%O_2} \right) \\
 &= \left(\frac{\text{g}}{\text{DSCM}} \right) \left(\frac{1}{16,018} \right) (F_d) \left(\frac{21}{21 - \%O_2} \right) \\
 &= \left(\frac{0.103}{16,018} \right) (9734^{****}) \left(\frac{21}{21 - 4.8} \right) \\
 &= 0.082 \text{ pounds SO}_2/\text{MBtu}
 \end{aligned}$$

This represents the rate of SO₃ passing from the economizer to the air heater.

* $\frac{\text{mg}}{\text{DSCM}}$ = milligrams per Dry Standard Cubic Meter

**R = Gas Constant

***F_d = The "F" factor (see Appendix D)

****From Appendix D

HEAT INPUT RATE

Several methods (listed below) have been used to find the heat input rate to the boiler during the Level 1 test.

o F - Factor Method

From Entropy's report (Appendix F) 4125 $\frac{\text{MBtu}}{\text{Hr}}$

o From Exxon coal analysis (Appendix B) and feed rate

$$\left(12,134 \frac{\text{Btu}}{\text{pound(wet)}}\right) \left(359,000 \frac{\text{Pounds(wet)}}{\text{Hr}}\right) = \dots\dots\dots 4356 \frac{\text{MBtu}}{\text{Hr}}$$

o Average of the above 4240 $\frac{\text{MBtu}}{\text{Hr}}$

FLOW RATES OF FLUE GASES (at 0% O₂, Dry)

Measured values (from Appendixes C and F)

o Entering Precipitator

$$(844,000 \text{ DSCF/min}) \left(\frac{21 - 5.7}{21}\right) = \dots\dots\dots 628,000 \text{ DSCF/min (at 0\% O}_2\text{)}$$

o Leaving Precipitator

$$(948,000 \text{ DSCF/min}) \left(\frac{21 - 5.7}{21}\right) = \dots\dots\dots 691,000 \text{ DSCF/min (at 0\% O}_2\text{)}$$

Calculated value (from F-factor and fuel feed rate)

$$\left(9734 \frac{\text{DSCF}}{\text{MBtu}}\right) \left(4240 \frac{\text{MBtu}}{\text{Hr}}\right) \left(\frac{1}{60} \frac{\text{Hr}}{\text{Min}}\right) = \dots\dots\dots 688,000 \text{ DSCF/min (at 0\% O}_2\text{)}$$

All values (3 different methods) agree reasonable well. The small differences can be explained by leakage around the precipitator, and by the accuracy of the raw data available from plant instruments.

CONVERSION FACTORS FOR COAL-FIRED BOILER EMISSIONS

The table shown below is based on the following assumptions:

- o At 0% excess air, complete combustion of bituminous coal produces 9820* standard cubic feet of gaseous combustion products (on a dry basis) per million Btu of heat content in the fuel. Similarly, on a wet basis (EPA assumes 8% moisture in the flue gas), the value is 10680 WSCF/MBtu.*
- o Typically, a pound of bituminous coal has a heat content of 11,000 Btu/pound (as fired basis: about 10% moisture) or 12,000 Btu/pound (dry basis).

Other information about the heat content, "F" factors, and combustion products of various fuels (based on fuel analysis) may be found in the reference cited on the bottom of this page.**

Coal Heat Content (Bituminous Coal)	11,000 Btu/lb (wet) 12,000 Btu/lb (dry)
Fuel Gas Flow Rate* (assuming perfect combustion and 0% excess air)	10,680 WSCF/MBtu or 9,820 DSCF/MBtu

Typically, when operating near full load, a large (400 MW) coal fired steam generator (boiler) will burn about 43 tons of coal per hour for every 100 MW of electricity it produces.

If the heat content of the fuel is about 11,000 Btu/pound, then at full load (400 MW):

$$\left(\begin{array}{c} \text{Emission Rate:} \\ \text{pounds/hour} \end{array} \right) = \left(\begin{array}{c} \text{Emission Rate:} \\ \text{pounds/MBtu} \end{array} \right) (3800 \text{ MBtu/Hr}^{***})$$

Example: A 400 MW boiler with particulate emissions of 0.7 lb/MBtu when at full load is emitting about 2700 pounds of particulate matter per hour.

*Based on "F" factors.

**G. J. Aldina, J. A. Jahnke, "Source Sampling for Particulate Pollutants" pp. 138-153, manual for course No. 450 of EPA's Air Pollution Training Institute. Prepared by Northrup Services Inc., under EPA contract No. 68-02-2374, January, 1978.

$$\begin{aligned}
 &^{***}(400 \text{ MW}) \left(\frac{43 \text{ tons/hour}}{100 \text{ MW}} \right) \left(\frac{2000 \text{ pounds}}{\text{ton}} \right) \left(\frac{11,000 \text{ Btu}}{\text{pound}} \right) = 3800 \times 10^6 \frac{\text{Btu}}{\text{hour}} \\
 &= 3800 \text{ MBtu/hr}
 \end{aligned}$$

APPENDIX E

GC ANALYSIS DATA

The pages that follow contain raw GC data. Each recorder printout is preceded by an operating log sheet describing the GC conditions during the analysis run. The first analysis is documented in considerable detail as an example to the reader. Such detail has been omitted from later pages. At the beginning of each set of chromatograms (one for each type of analysis - permanent gases, sulfur compounds, hydrocarbons, etc.) is a narrative describing the results and problems related to that set of analysis.

PERMANENT (FIXED) GAS ANALYSIS

The following few pages contain data and calculation results pertaining to the analysis of the permanent gases (CO_2 , O_2 , etc.). After calculating response factors based on the GC plot in the calibration run, the results were written directly on that plot. At that point, it seemed that the subsequent analysis of an unknown sample would be quite simple. Unfortunately, that was not the case.

During the flue gas sample analysis, the computing integrator did not resolve the O_2 and N_2 peaks. However, since peak area is almost proportional to peak height, (and attenuation) it was felt that the peak areas for O_2 and N_2 in the sample run could be determined from the peak height and areas in the calibration run. But when this was done, the sum of the O_2 and N_2 areas did not agree with the value reported by the computing integrator. The method seemed to apply to the relatively small O_2 peak, but could not be used for the tall, wide N_2 peak.

The resolution of the O_2 - N_2 peak was finally accomplished by a peak height measurement method for O_2 , and area difference method for N_2 where the O_2 is assumed to be a negligible part of the total O_2 - N_2 peak area (as was the case during the calibration run).

During the many calibration runs (only one is presented here), the response factors of some of the "Cal Gas" components (especially nitrogen) varied from run to run by a factor of about 2. Hence, it is obvious that the calibration is valid only for a small range of concentrations. The reader should take this into account when considering GC results that differ greatly from the calibration value. The results of the permanent gas analysis are shown Table GE-1.

TABLE GE-1
PERMANENT GAS ANALYSIS

Gas	Response Factor (From Calibration Run)	Peak Area or Height (From Sample Run)	Sample Concentration
H ₂	2.2×10^3 area units/%	109 (area)	0.05%
O ₂	1.375 cm, height/%*	7.5 cm (height)*	5.5%
N ₂	119×10^3 area units/%	9813×10^3 (area)	82%
CO	560 area units/ppm	284×10^3 (area)	507 ppm**
H ₂ O	—	—	—
CO ₂	170×10^3 area units/%	2246×10^3 (area)	13%
CH ₄	—	Not Found	—

*All values reported here (response factor, peak heights and response) are given at the same plotter attenuation (AT=64).

**This may be out of the range for which the calibration is valid.

Table GE-2

Gas Chromatograph Conditions for
Permanent Gas Calibration Run (Figure GE-1).

Injection date 10-15-80, Time _____ AM PM, Day of Week Wednesday
 Page number(s) (from recorder print-out) 32
 Total integrated area (from recorder print-out) 12969501
 Purpose of run calibration run/permanent gases O₂, CO₂, N₂, ... ETC

Sample origin or description cal gas cylinder described below

Amount injected 1.0 cc, Port used (A or B?) _____, Chart speed: CS = _____ cm/min.
 Detector Attenuation: AT = 2, Amplifier or range X 1
☒ Dual HWD (TCD) Current low
☐ FID
☐ FPD Is filter in sulfur position? _____

Column
 Liquid phase carboxeave S
 Solid phase _____, Mesh size ~100/120
 Length 7 ft., OD 1/8 inch, ID _____ mm, Material SS

Temperatures
 Injector ~200 °C, Detector 200 °C
 Oven: 35 °C for 4 minutes,
 then ramp up at 25 °C/min to 175 °C, and hold. for _____ min.,
 then ramp up at _____ °C/min to _____ °C, and hold for _____ min.

Carrier gas helium
 Flow rate settings: A 40 cc/min, B 40 cc/min, Rates verified? _____
 Pressures (from GC's gauges)
 Air A _____ psig, Air B _____ psig, H₂ _____ psig
 Carrier gas _____ psig, Column head loss: A _____ psig, B _____ psig
 A - B pushbuttons (in or out) A _____ B _____
 If this is a calibration run:
 Cal gas cylinder number _____
 Cal gas supplier Mattheson

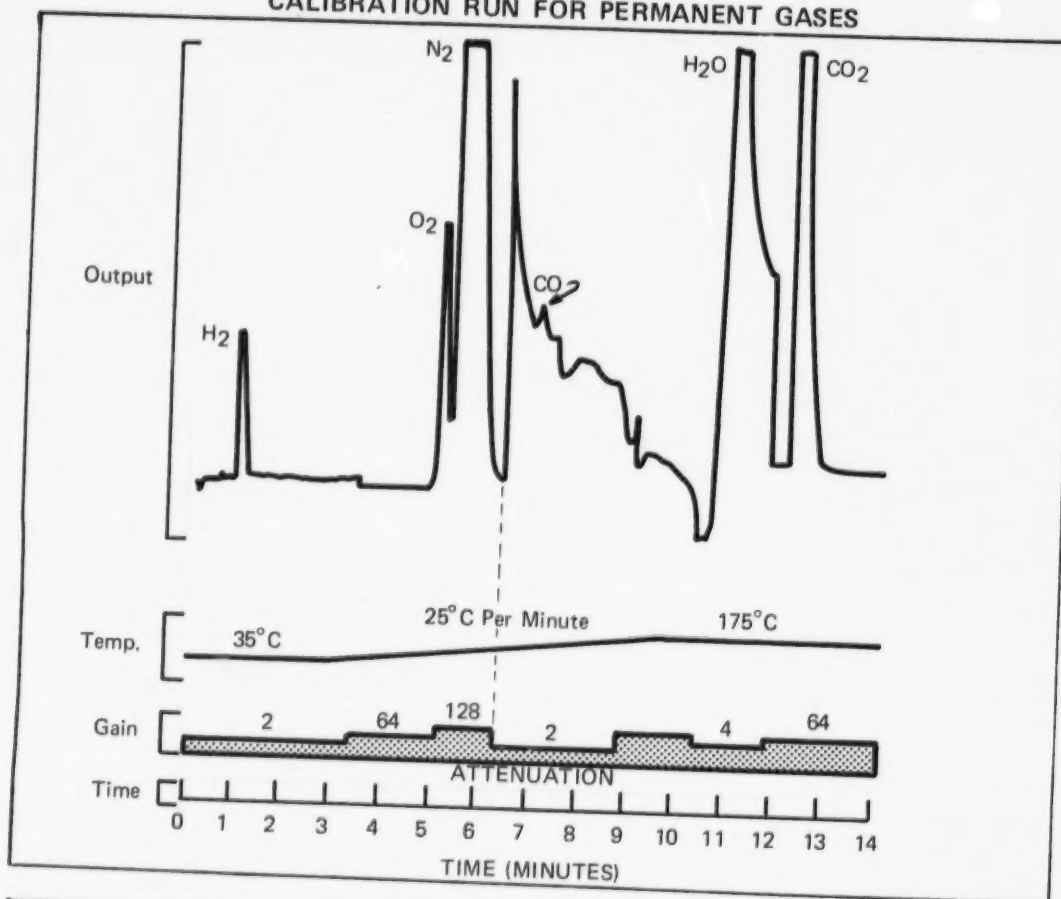
Concentrations

Nitrogen	<u>80</u>	% ~~or~~ <u>ppm</u>
H ₂	<u>1</u>	% ~~or~~ <u>ppm</u>
O ₂	<u>4</u>	% ~~or~~ <u>ppm</u>
CH ₄	<u>25</u>	% ~~or~~ <u>ppm</u>
CO	<u>175</u>	% ~~or~~ <u>ppm</u>
CO ₂	<u>13</u>	% ~~or~~ <u>ppm</u>
_____	_____	% or ppm
_____	_____	% or ppm

Comments _____

Name of operator RUN LABAST Date 10-15, 1980

Figure GE-1
CALIBRATION RUN FOR PERMANENT GASES



CALIBRATION RUN - PERMANENT GASES (10-15-80)
(See previous page for GC operating conditions and description of this run.)

PEAK#	AREA%	RETENTION TIME	AREA	CAL GAS CONCEN.	RESP. FACTOR (AREA/CONCEN.)
1 H ₂	0.017	0.9	2160	1%	2.2x10 ³ /PCNT
2 O ₂	0.199	4.48	25822	4%	6.5x10 ³ /PCNT*
3 N ₂	73.533	5.28	9536893	80%	119x10 ³ /PCNT
4 CO	0.753	6.93	97618	175 PPM	560/PPM
5 —	1.809	7.73	234606	—	—
6 —	1.929	9.12	250225	—	—
7 H ₂ O	4.725	10.93	612846	—	—
8 CO ₂	17.035	12.24	2209331	13%	170x10 ³ /PCNT
CH ₄		~10		25 PPM	Peak Not Seen
Total	100.		12969501		

*5.5 cm Peak Height/4% Conc. = 1.375 cm/% (@At = 64)

Table GE-3

Gas Chromatograph Conditions for Permanent
Gas Sample Run (Figure GE-2)

GAS CHROMATOGRAPH OPERATING CONDITIONS

Injection date 10-15-80, Time 12:10 noon AM PM, Day of Week Wednesday
Page number(s) (from recorder print-out) 34
Total integrated area (from recorder print-out) 13030425
Purpose of run Analysis of flue gas for permanent gases (CO₂, O₂, N₂, etc.)

Sample origin or description flue duct at economizer outlet

Amount injected 1 cc, Port used (A or B?) _____, Chart speed: CS = _____ cm/min.
Detector Attenuation: AT = _____, Amplifier or range X 1

☒ Dual HWD (TCD) Current low

☐ FID

☐ FPD

Is filter in sulfur position? _____

Column

Liquid phase carbosieve S

Solid phase _____, Mesh size 100/120

Length 7 ft., OD 1/8 inch, ID _____ mm, Material SS

Temperatures

Injector 200 °C, Detector 200 °C

Oven: 35 °C for 4 minutes,

then ramp up at 25 °C/min to 175 °C, and hold for _____ min.,

~~then ramp up at _____ °C/min to _____ °C, and hold for _____ min.~~

Carrier gas He

Flow rate settings: A 40 cc/min, B 40 cc/min, Rates verified? _____

Pressures (from GC's gauges)

Air A _____ psig, Air B _____ psig, H₂ _____ psig

Carrier gas _____ psig, Column head loss: A _____ psig, B _____ psig

A - B pushbuttons (in or out) A _____ B _____

If this is a calibration run:

Cal gas cylinder number _____

Cal gas supplier _____

Concentrations

Nitrogen _____ % or ppm

_____ % or ppm

_____ % or ppm

_____ % or ppm

_____ % or ppm

_____ % or ppm

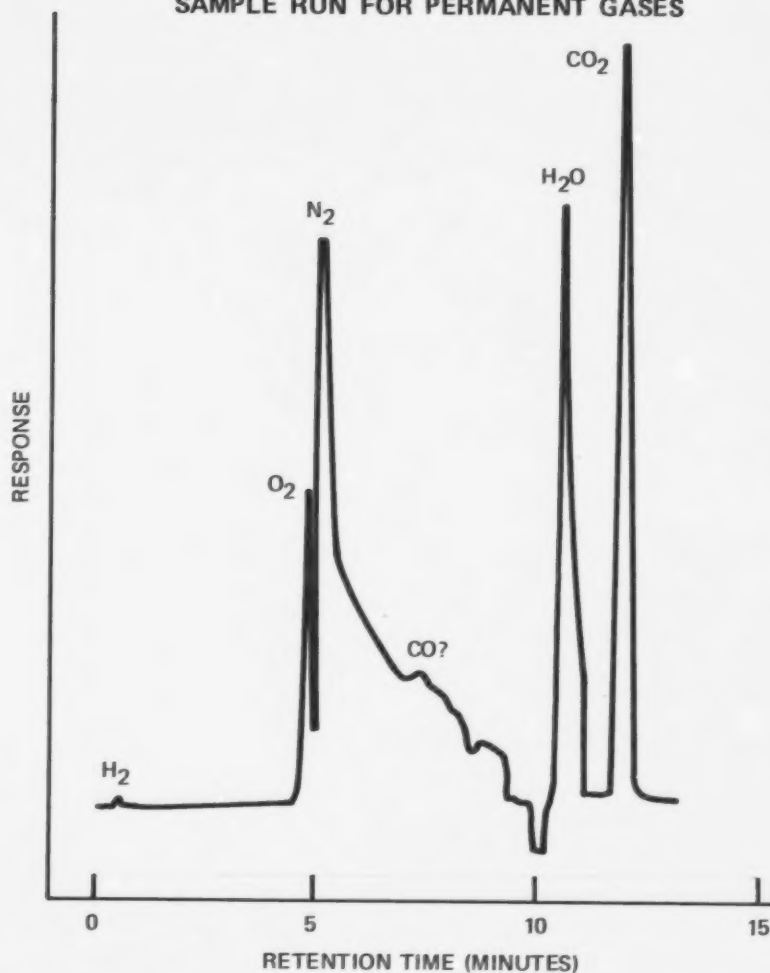
_____ % or ppm

_____ % or ppm

Comments Computing integrator did not resolve the O₂ and N₂ peaks. The height ratio method does not add up to a reasonable amount. These peaks look similar to the corresponding cal gas peaks. Recorder attenuation was changed frequently during the run as indicated.

Name of operator RON LABAST Date OCT. 15, 1980

Figure GE-2
SAMPLE RUN FOR PERMANENT GASES



PEAK#	AREA%	RETENTION TIME	AREA
1 H ₂	0.001	0.57	109
2 O ₂ N ₂ *	75.309	5.23	9813115
3 CO	2.186	7.58	284837
4 ?	1.727	9.12	225048
5 H ₂ O	3.534	10.88	460515
6 CO ₂	17.243	12.27	2246801
Total	100.		13030425

*It is assumed that, as in the calibration run, O₂ makes a negligible contribution to this total area. Here, the O₂ concentration may be calculated by the peak height method.

SULFUR COMPOUND ANALYSIS

Equipment problems prevented this analysis by GC. For SO_2 , and SO_3 , wet chemistry methods were used instead. The results of the Level 1 test results for SO_x are presented in Section IV-A-3 of Part C of this report.

NITROGEN-CONTAINING GAS ANALYSIS

(NH_3 , HCN, NCCN)

During calibration runs with NH_3 , HCN, and NCCN the calibration peaks were nearly undetectable (see Figures GE-3 and GE-4). The peaks during the sample analysis run for these compounds were even less obvious. Hence, it was concluded that for NH_3 , HCN, and NCCN, the flue gas contained lower concentrations for each than the corresponding value in the calibration gas, and each was below the limit of detectability (130 ppm for HCN, 170 ppm for NCCN, and 190 ppm for NH_3).

HYDROCARBON ANALYSIS

The flame ionization detector is essentially a hydrogen-carbon bond counter. It responds almost exclusively to hydrocarbons and, within a family type (e.g.: straight chain, normal alkanes), gives a response factor (per volume concentration in gas) that is proportional to the carbon number. (On a mass basis, response factors will be more uniform.)

Also, within a family type (when the family type is known), there are certain rules (e.g.: Kovats Relative Index) that can be used to identify a hydrocarbon through measurement of the retention time of its peak.

In the case of the flue-gas chromatograms shown in this section (Figures GE-7 and GE-9), it is fairly certain that most of the peaks are not due to normal straight chain alkanes since the peaks do not match those of the calibration runs (Figures GE-6 and GE-8). It is more likely that those peaks are due to more complex hydrocarbons and the peaks with longer retention times probably represent organic compounds having higher carbon numbers.

The 20% SP-2100 column (used for the analysis of the heavy hydrocarbons) is a "boiling point" column. (That is, it separates compounds according to their boiling points. And, since the flame ionization detector responds only to hydrocarbons, the resulting chromatogram for this column - detector combination is a trace of hydrocarbons separated according to boiling point. Generally, for relatively simple hydrocarbons, the boiling point depends on the carbon number to a larger degree than it does on the hydrocarbon type. Furthermore, retention time (relative to an unretained peak) will follow a logarithmic rule with a doubling of carbon number resulting in a quadrupling of retention time. These properties, when considered with the following chromatograms (Figures GE-7 and GE-9) indicate that no simple hydrocarbons were detected with carbon number greater than about C₁₀.

If further work in this area is desired, it might be wise to consider the use of a mass spectrometer, to identify some of the unknown hydrocarbons. Alternatively, the injection of a single known liquid hydrocarbon could be used as a reference against which the relative retention times of the unknown peaks could be calculated with greater certainty.

Table GE-4

GC Conditions during Calibration Run for
Light Hydrocarbons. (Figure GE-3)

GAS CHROMATOGRAPH OPERATING CONDITIONS

Injection date 10-15-80, Time 10:30 AM PM Day of Week Wednesday
Page number(s) (from recorder print-out) 59
Total integrated area (from recorder print-out) 1825852
Purpose of run Calibration for analysis of light hydrocarbons

Sample origin or description Cal Gas Lecture Bottle

Amount injected 1 cc, Port used (A or B?) , Chart speed: CS = cm/min.
Detector Attenuation: AT = 4, Amplifier or range X

☐ Dual HWD (TCD) Current

☒ FID

☐ FPD

Is filter in sulfur position?

Column

Liquid phase Poropak Q

Solid phase

Length 6 ft., OD 1/4 inch, ID 2 mm, Mesh size 60/80

Temperatures

Injector 100 °C, Detector 200 °C

Oven: 60 °C for 4 minutes,

then ramp up at 20 °C/min to 110 °C, and hold for min.,
~~then ramp up at °C/min to °C, and hold for min.~~

Carrier gas HE

Flow rate settings: A cc/min, B cc/min, Rates verified?

Pressures (from GC's gauges)

Air A psig, Air B psig, H₂ psig

Carrier gas psig, Column head loss: A psig, B psig

A - B pushbuttons (in or out) A B

If this is a calibration run:

Cal gas cylinder number

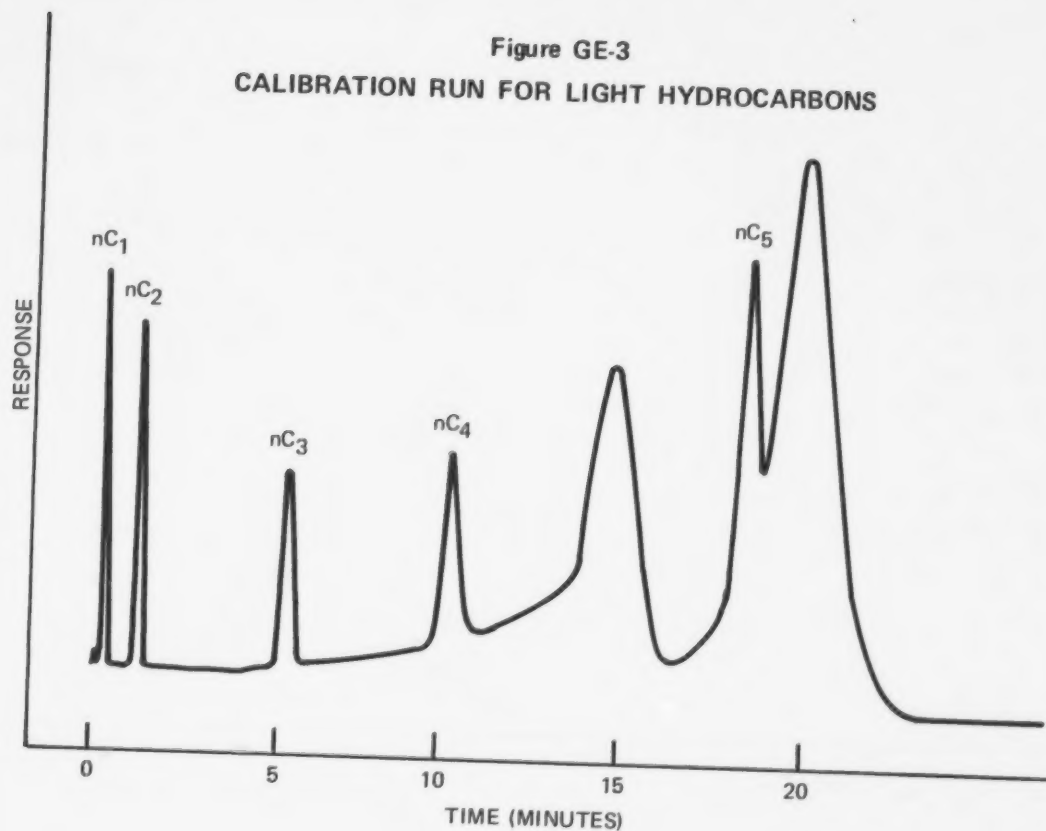
Cal gas supplier SCOTT

Concentrations

<u>Nitrogen</u>	<u>Balance</u>	<u>% or ppm</u>
<u>CH₄</u>	<u>15.1</u>	<u> </u> or ppm
<u>nC₂</u>	<u>14.8</u>	<u> </u> or ppm
<u>nC₃</u>	<u>15.7</u>	<u> </u> or ppm
<u>nC₄</u>	<u>15.2</u>	<u> </u> or ppm
<u>nC₅</u>	<u>16.2</u>	<u> </u> or ppm
<u>nC₆</u>	<u>17.1</u>	<u> </u> or ppm
<u>nC₇</u>	<u>13.1</u>	<u> </u> or ppm

Comments Cal Gas is a mixture of normal alkanes.

Name of operator RON LABAST Date 10-15, 1980



PEAK#	AREA%	RETENTION TIME	AREA	CONCEN. (PPM)	RESPONSE FACTOR (AREA/PPM)
1 nC ₁	1.024	0.33	18702	15.1	1239
2 nC ₂	1.876	1.37	34251	14.8	2314
3 —	0.017	5.09	308	—	—
4 nC ₃	2.794	5.64	51013	15.7	3249
5 nC ₄	8.126	10.29	148368	15.2	9761
6 —	1.035	11.25	18889	—	—
7 —	26.247	14.93	479226	—	—
8 nC ₅	15.25	18.93	278448	16.2	17188
9 —	43.632	20.43	796647	—	—
Total	100.		1825852		

Table GE-5

GC Conditions during Sample Run for Light Hydrocarbons
(Figure GE-4)

GAS CHROMATOGRAPH OPERATING CONDITIONS

Injection date 10-15-80, Time 9:30 AM (PM) Day of Week Wednesday
Page number(s) (from recorder print-out) 55-56
Total integrated area (from recorder print-out) 2406187
Purpose of run flue gas analysis for light hydrocarbons

Sample origin or description flue duct between economizer and air heater

Amount injected 1 cc, Port used (A or B?) , Chart speed: CS = cm/min.
Detector Attenuation: AT = as indicated, Amplifier or range X

☐ Dual HWD (TCD) Current

☒ FID

☐ FPD

Is filter in sulfur position?

Column

Liquid phase Poropak Q

Solid phase

Mesh size 60/80

Length 6 ft., OD 1/4 inch, ID 2 mm, Material Glass

Temperatures

Injector 100 °C, Detector 200 °C

Oven: 60 °C for 4 minutes,

then ramp up at 20 °C/min to 110 °C, and hold for min.,

then ramp up at °C/min to °C, and hold for min.

Carrier gas He

Flow rate settings: A 25 cc/min, B 25 cc/min, Rates verified?

Pressures (from GC's gauges)

Air A psig, Air B psig, H₂ psig

Carrier gas psig, Column head loss: A psig, B psig

A - B pushbuttons (in or out) A B

If this is a calibration run:

Cal gas cylinder number

Cal gas supplier

Concentrations

Nitrogen

 % or ppm

 % or ppm

 % or ppm

 % or ppm

 % or ppm

 % or ppm

 % or ppm

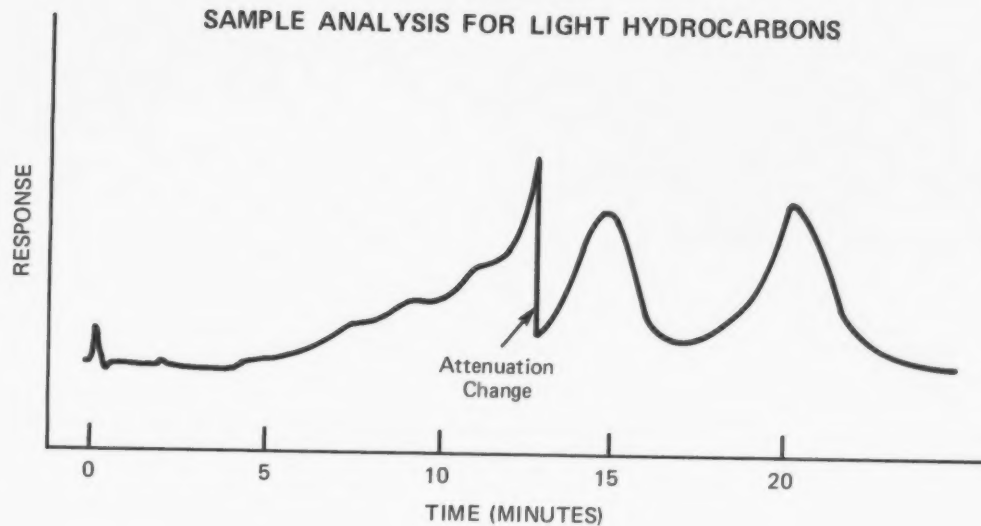
 % or ppm

Comments

Name of operator RON LABAST Date 10-15, 1980

Figure GE-4

SAMPLE ANALYSIS FOR LIGHT HYDROCARBONS



PEAK#	AREA%	RETENTION TIME	AREA	CONCENTRATION
1	0.066	0.29	1582	C₄ ? (9760/PPM) = 4 PPM
2	0.05	0.37	1204	
3	0.009	0.49	219	
4	0.014	2.19	338	
5	0.474	6.69	11417	
6	1.315	8.67	31631	
7	1.792	10.39	43127	
8	2.137	11.85	51424	
9	41.574	14.91	1000360	
10	52.568	20.31	1264885	
Total	100.		2406187	

Table GE- 6

GC Conditions during Calibration Run
for heavy hydrocarbons (Figure GE-5)

GAS CHROMATOGRAPH OPERATING CONDITIONS

Injection date 10-16-80, Time _____ AM PM, Day of Week Thursday
Page number(s) (from recorder print-out) 69
Total integrated area (from recorder print-out) 472955
Purpose of run Calibration for analysis of heavy hydrocarbons

Sample origin or description Cal Gas Lecture Bottle

Amount injected 1 cc, Port used (A or B?) _____, Chart speed: CS = 1 cm/min.
Detector Attenuation: AT = 16, Amplifier or range X 1

☐ Dual HWD (TCD) Current low

☒ FID

☐ FPD

Is filter in sulfur position? _____

Column

Liquid phase 20% SP 2100

Solid phase Supelcoport, Mesh size 80/100

Length 6 ft., OD 1/4 inch, ID 2 mm, Material Glass

Temperatures

Injector 200 °C, Detector 200 °C

Oven: 33 °C for _____ minutes,

then ramp up at _____ °C/min to _____ °C, and hold for _____ min.,

then ramp up at _____ °C/min to _____ °C, and hold for _____ min.

Carrier gas He

Flow rate settings: A 20 cc/min, B 20 cc/min, Rates verified? _____

Pressures (from GC's gauges) Setting

Air A _____ psig, Air B _____ psig, H₂ _____ psig

Carrier gas _____ psig, Column head loss: A _____ psig, B _____ psig

A - B pushbuttons (in or out) A _____ B _____

If this is a calibration run:

Cal gas cylinder number _____

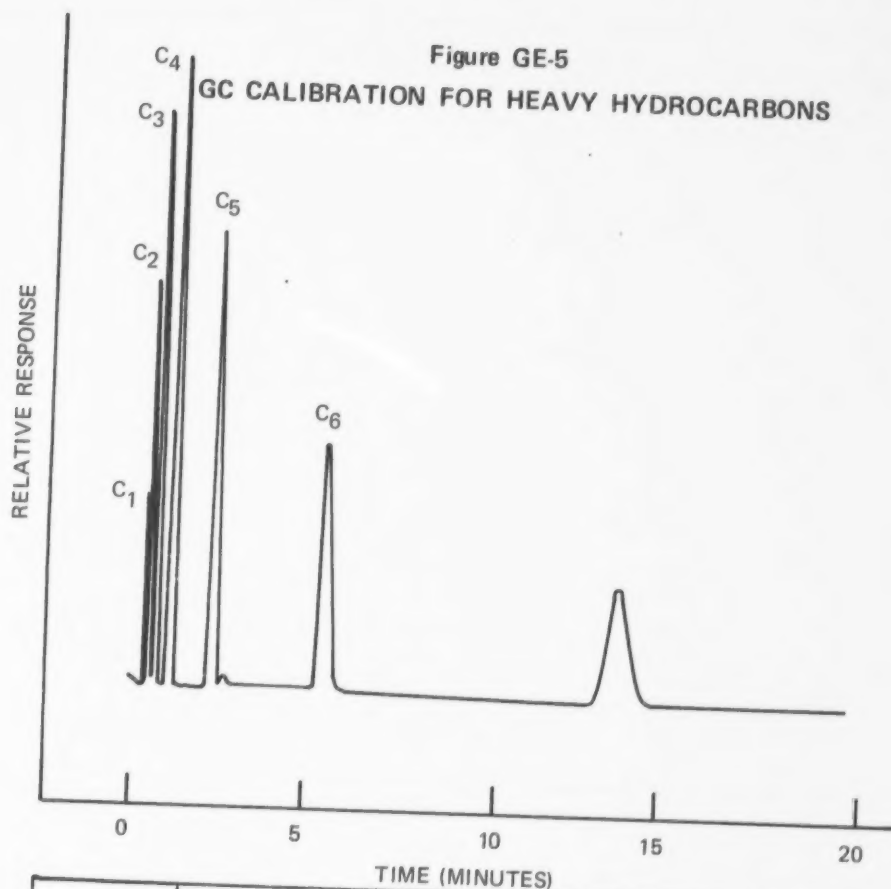
Cal gas supplier _____

Concentrations

Nitrogen	Balance	% or ppm
<u>CH₄</u>	<u>15.1</u>	<u>% or ppm</u>
<u>nC₂</u>	<u>14.8</u>	<u>% or ppm</u>
<u>nC₃</u>	<u>15.7</u>	<u>% or ppm</u>
<u>nC₄</u>	<u>15.2</u>	<u>% or ppm</u>
<u>nC₅</u>	<u>16.2</u>	<u>% or ppm</u>
<u>nC₆</u>	<u>17.1</u>	<u>% or ppm</u>
<u>nC₇</u>	<u>13.1</u>	<u>% or ppm</u>

Comments _____

Name of operator RON LABIN Date 10-16, 1980



PEAK#	AREA%	RETENTION TIME	AREA	CONCEN. (PPM)	RESPONSE FACTOR (AREA/PPM)
1 —	0.219	0.01	1036	—	—
2 —	0.002	0.27	10	—	—
3 C ₁	2.107	0.33	9965	15.1	660
4 C ₂	8.071	0.4	38173	14.8	2579
5 C ₃	10.976	0.55	51913	15.7	3307
6 —	0.035	0.79	165	—	—
7 C ₄	14.559	1.	68856	15.2	4530
8 —	0.053	1.77	253	—	—
9 C ₅	18.16	2.2	85888	16.2	5302
10 —	0.879	2.54	4157	—	—
11 —	0.024	3.81	113	—	—
12 C ₆	19.733	5.36	93330	17.1	5458
13 —	0.633	12.3	2994	—	—
14 C ₇ ?	22.158	13.79	104796	13.1	8000
15 —	1.694	16.56	8013	—	—
16 —	0.29	18.	1370	—	—
17 —	0.272	18.11	1288	—	—
18 —	0.134	19.02	635	—	—
Total	100.		472955		

Table GE-7

GC Conditions during sample analysis
for heavy hydrocarbons (Figure GE-6)

GAS CHROMATOGRAPH OPERATING CONDITIONS

Injection date 10-16-80, Time _____ AM PM, Day of Week Thursday
Page number(s) (from recorder print-out) 67
Total integrated area (from recorder print-out) 61997
Purpose of run Analysis of Heavy Hydrocarbons

Sample origin or description flue duct between economizer and air heater

Amount injected 1 cc, Port used (A or B?) _____, Chart speed: CS = 1 cm/min.
Detector Attenuation: AT = 2, Amplifier or range X 1

☐ Dual HWD (TCD) Current low

☒ FID

☐ FPD

Is filter in sulfur position? _____

Column

Liquid phase 20% SP 2100

Solid phase Supelcoport, Mesh size 80/100

Length 6 ft., OD 1/4 inch, ID 2 mm, Material Glass

Temperatures

Injector 200 °C, Detector 200 °C

Oven: 33 °C for _____ minutes,

then ramp up at _____ °C/min to _____ °C, and hold for _____ min.,

then ramp up at _____ °C/min to _____ °C, and hold for _____ min.

Carrier gas He

Flow rate settings: A 20 cc/min, B 20 cc/min, Rates verified? _____

Pressures (from GC's gauges) Setting

Air A _____ psig, Air B _____ psig, H₂ _____ psig

Carrier gas _____ psig, Column head loss: A _____ psig, B _____ psig

A - B pushbuttons (in or out) A _____ B _____

If this is a calibration run:

Cal gas cylinder number _____

Cal gas supplier _____

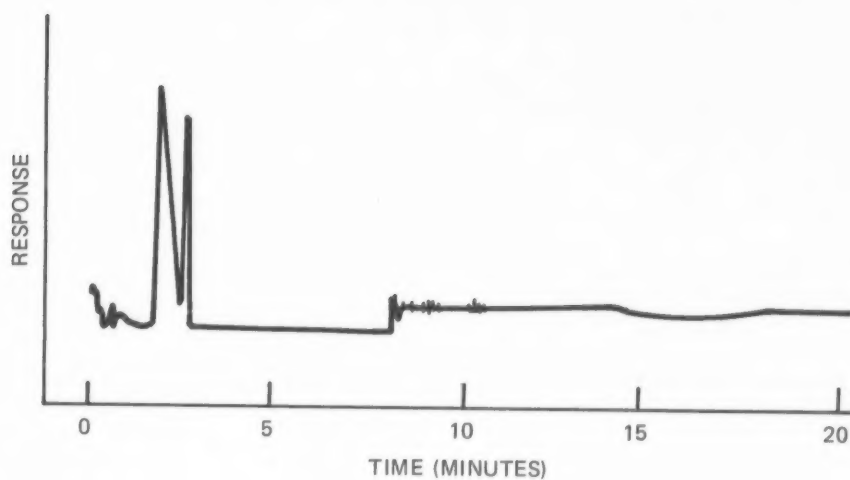
Concentrations

Nitrogen	_____	% or ppm
_____	_____	% or ppm
_____	_____	% or ppm
_____	_____	% or ppm
_____	_____	% or ppm
_____	_____	% or ppm
_____	_____	% or ppm
_____	_____	% or ppm

Comments _____

Name of operator Lon L. B. W. Date 10-16, 1980

Figure GE-6
GC SAMPLE ANALYSIS FOR HEAVY HYDROCARBONS



PEAK#	AREA%	RETENTION TIME	AREA
1	3.703	0.02	2296
2	1.024	0.2	635
3	2.897	0.24	1796
4	0.071	0.3	44
5	5.721	0.51	3547
6	2.124	0.62	1317
7	55.064	1.78	34138
8	20.14	2.56	12486
9	0.008	3.18	5
10	1.173	8.45	727
11	0.239	8.52	148
12	0.832	8.56	516
13	0.232	9.48	144
14	6.771	20.53	4198
Total	100.		61997

APPENDIX F

PORTIONS OF METHOD 5 REPORT
(By Entropy Environmentalists)

This appendix reports the results of particle mass loading tests (EPA Method 5) performed both upstream and downstream of the electrostatic precipitator concurrently with the other Level 1 tests.

SUMMARY OF RESULTS

Table 1 presents the inlet and outlet particulate concentrations (grains per dry standard cubic foot), the electrostatic precipitator's collection efficiency, and the outlet particulate emission concentration. Individual run summaries for the inlet and outlet locations are presented in Tables 2 and 3, respectively.

TABLE 1

UNIT #3 PRECIPITATOR COLLECTION EFFICIENCIES AND PARTICULATE EMISSIONS

Simultaneous Run Numbers		Concentration Grains Per Dscf		Collection Efficiency	Outlet Pounds Per MBtu
<u>Inlet</u>	<u>Outlet</u>	<u>Inlet</u>	<u>Outlet</u>	<u>Percent</u>	<u>Particulate</u>
1	4	3.96	0.0525	98.7	0.0963
2	5	4.40	0.0389	99.1	0.0792
3	6	4.76	0.0153	99.7	0.0303
Average		4.37	0.0356	99.2	0.0686

TABLE 2

PARTICULATE TESTS SUMMARY OF RESULTS

Electrostatic Precipitator Inlet Unit No. 3

Test Number	Test 1	Test 2	AVG. 1&2	Test 3
Date	10/15/80	10/15/80		10/16/80
Stack Temperature, Deg. F	296	303		293
Stack Flow Rate SCFM* Dry at 5.7% O ₂	785,000	895,000	840,000	734,000
Stack Flow Rate ACFM, Wet	1,230,000	1,460,000		1,180,000
Volume of Gas Sampled SCF* Dry	87.96	101.4		86.63
Percent Isokinetic	96.1	97.2		101.3
<u>Method 5 Results:</u>				
Milligrams	22,556.8	28936.9		26,730.8
Grains Per DSCF*	3.95	4.40		4.76
Pounds Per Hour	26,600	33,800	30,200	29,900

*68 Deg. F, 29.92 in Hg

TABLE 3

PARTICULATE TESTS SUMMARY OF RESULTS

Electrostatic Precipitator Outlet Unit No. 3

Test Number	Test 4	Test 5	AVG. 4 & 5	Test 6	AVG. 4, 5, & 6
Date	10/15/80	10/15/80		10/16/80	10/16/80
Stack Temperature, Deg. F	292	309		293	
Stack Flow Rate SCFM* Dry at 5.7% O ₂	938,000	957,000	948,000	915,000	937,000
Stack Flow Rate ACFM, Wet	1,510,000	1,580,000		1,470,000	
Volume of Gas Sampled SCF* Dry	67.07	69.48		67.84	
Percent Excess Air	30	43		40	
Heat Input Rate - F Factor Million Btu/hr	4,389	4,028		3,959	4,125
Percent Isokinetic	101.4	104.2		106.4	
<u>Method 5 Results:</u>					
Milligrams	228.3	175.2		67.2	
Grains Per DSCF*	0.0525	0.0389		0.0153	
Pounds Per Hour	422	319		120	
Pounds Per Million Btu	0.0963	0.0792		0.0303	

*68 Deg. F, 29.92 in Hg

PROCESS DESCRIPTION AND OPERATION

The Mill Creek Station of Louisville Gas and Electric Company employs coal-fired boilers for the generation of electricity. This report covers the testing of Unit No. 3.

As shown in Figure 1, Unit No. 3 has two parallel sets of heat exchangers and control equipment after the boiler; only the "A"-side will be discussed. Flue gases leaving the boiler pass through an air preheater, an electrostatic precipitator, an induced draft fan, and a sulfur dioxide scrubber before exhausting out the stack. Potential pollutants include the products of complete and incomplete combustion of the coal.

During the testing on October 8 and 9, 1980, Unit No. 3 was producing 400 megawatts, as reported by Louisville Gas & Electric Company, with an average heat input of 4125 million Btu per hour, as calculated by the F-factor method.

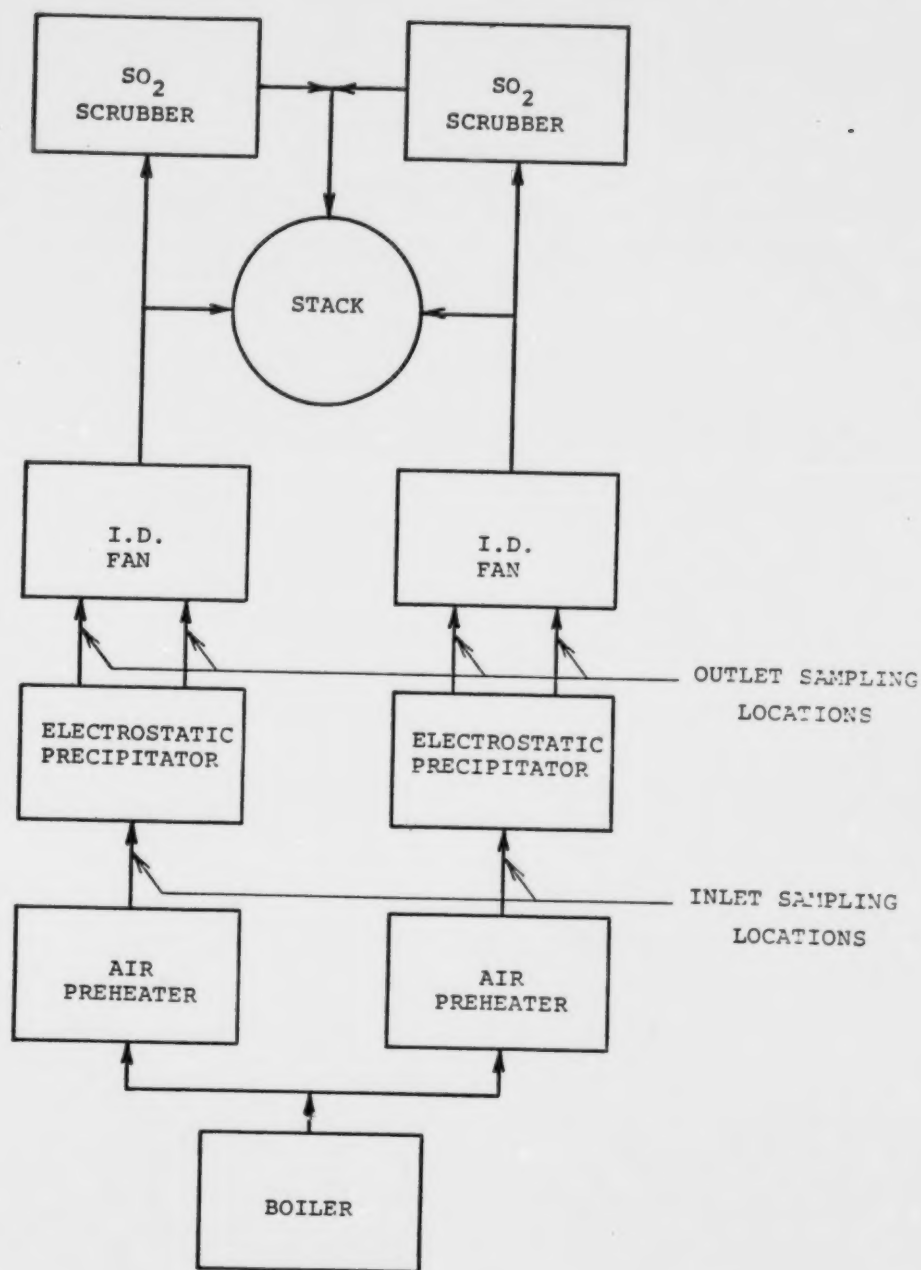


FIGURE 1. PROCESS AIR FLOW SCHEMATIC SHOWING SAMPLING LOCATIONS.

APPENDIX G

30-DAY CEM TEST
SUPPLEMENTAL INFORMATION

EXPERIMENTAL PROCEDURES FOR THE 30-DAY TESTS

The test boiler, Unit 3 of the Mill Creek Generating Station of the Louisville Gas and Electric Co., is rated at 425 megawatts electrical generating capacity. The boiler is a Babcock and Wilcox pulverized coal-fired unit rated at 825 MW (thermal) $2,816 \times 10^3$ lb/hr steam flow. During these 30-day tests, flue gas was sampled continuously from the flue duct, just upstream of the air heater.

Two 30-day tests were performed on the Louisville boiler (January to February 1981 and February to April 1981). During each test, boiler load was recorded along with a semi-continuous record (once every four seconds) of stack emissions. Also, at periodic intervals, the performance (zero and span drift, response time, accuracy, etc.) of each continuous emission monitor was evaluated according to EPA procedures to ensure good performance and quality data. This section presents a description of the instrumentation used to measure the gaseous emissions, the test procedures, and the techniques for certifying the continuous monitor system.

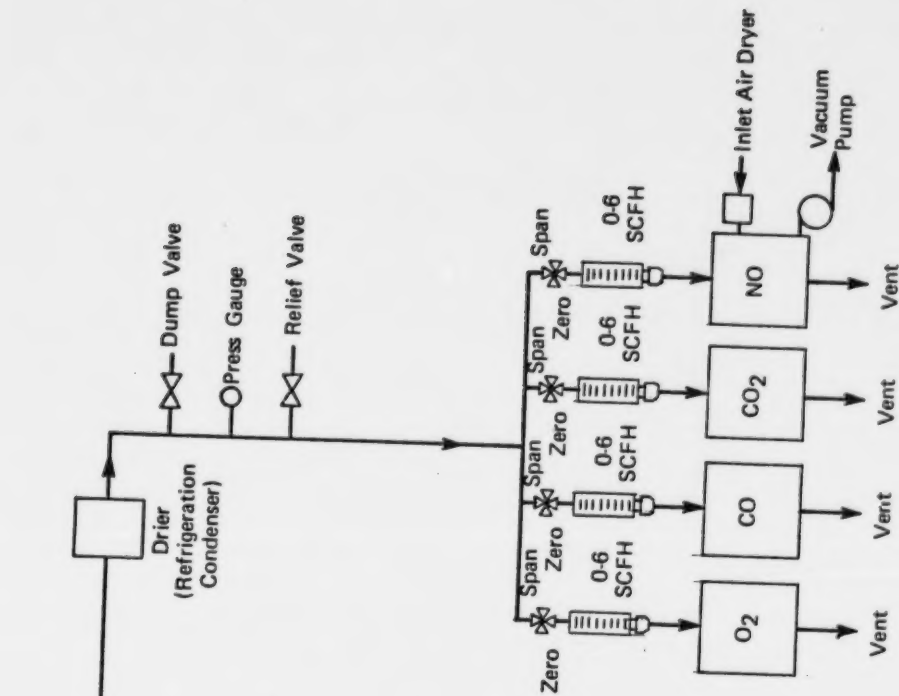
The emissions measurements were made using a continuous monitor fabricated by KVB, and assembled as a transportable package. Gaseous emission measurements were made with the analytical instruments listed in Table GG-1. All measurements were made and reported on a dry basis.

TABLE GG-1

ANALYTICAL INSTRUMENTATION

Emission Species	Manufacturer	Measurement Method	Model No.
Nitrogen Oxides	Thermo Electron	Chemiluminescent	10BR
Oxygen	Beckman Instrument	Polarographic	742
Carbon Dioxide	Horiba Instrument	NDIR	PIR-2000
Carbon Monoxide	Horiba Instrument	NDIR	PIR-2000

The continuous monitor is equipped with analytical instruments to measure concentrations of NO, CO, CO₂, and O₂. The sample gas is delivered to the analyzers at the proper condition and flow rate through the sampling and conditioning system shown schematically in Figure GG-1. A probe with a 0.7-micrometer sintered stainless steel filter was installed in the stack to sample the flue gas. The following paragraphs describe the analytical instrumentation.



Instrument	Operating Range	Calibration Gases
O ₂	0 - 10%	5%/9.27%
CO	0 - 1000 ppm	500 ppm/900 ppm
CO ₂	0 - 20%	10%/17.8%
NO	0 - 250 ppm	120.5 ppm/234 ppm

FIGURE GG-1
SCHEMATIC OF CONTINUOUS MONITOR SAMPLING AND CONDITIONING SYSTEM

Nitrogen Oxides

The oxides of nitrogen monitoring instrument used was a Thermo Electron chemiluminescent nitric oxide analyzer. The operational basis of the instrument is the chemiluminescent reaction of NO and O₃ to form NO₂ in an excited state. The resulting chemiluminescence is monitored through an optical filter by a high sensitivity photomultiplier tube, the output of which is electronically processed so it is linearly proportional to the NO concentration.

Air for the ozonator is drawn from ambient through an air dryer and a 10-micrometer filter element. Flow control for the instrument is accomplished by means of a small bellows pump mounted on the vent of the instrument downstream of a separator which insures that no water collects in the pump.

The basic analyzer is sensitive only to NO molecules. To measure NO_x (i.e., NO + NO₂), the NO₂ is first converted to NO. This is accomplished by a converter which is included with analyzer. The conversion occurs as the gas passes through a thermally insulated, resistance heated, stainless steel coil. With the application of heat, NO₂ molecules in the sample gas are reduced to NO molecules, and the analyzer then reads NO_x. NO₂ is obtained by the difference in readings obtained with and without the converter in operation.

Specifications for the Nitrogen Oxides Analyzer

Accuracy: 1% of full scale
Span drift: + 1% of full scale in 24 hours
Zero drift: + 1 ppm in 24 hours
Power requirements: 115 ± 10V, 60 Hz, 1000 watts
Response: 90% of F.S. in 1 sec (NO_x mode); 0.7 sec (NO mode)
Output: 4-20 ma
Sensitivity: 0.5 ppm
Linearity: + 1% of full scale
Vacuum detector operation
Ranges: 2.5, 10, 25, 100, 250, 1000, 2500, 20,000 ppm F.S.

Only the NO concentration was measured during this program. Because of the added complexity of heated sample lines and controllers necessary for measuring NO₂ and the small percentage of NO₂ in the flue gas, based on previous tests (Ref. 1, 2 and 3), it was decided that only NO measurement was necessary. Therefore, an unheated sample line was installed, and the moisture was removed from the sample gas by a dropout flask and a refrigerated condenser.

Carbon Monoxide and Carbon Dioxide

Carbon monoxide (CO) and carbon dioxide (CO₂) concentrations were measured by Horiba Instruments PIR-2000 short-path-length nondispersive infrared analyzers. These instruments measure the difference in infrared energy absorbed from energy beams passed through a reference cell (containing a

gas selected to have minimal absorption of infrared energy in the wave length absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale of zero to 100% and is then related to the concentration of the species of interest by calibration curves supplied with the instrument. A linearizer was supplied with the CO analyzer to provide a linear output over the range of interest. The operating ranges for the CO analyzer are zero to 500, zero to 1000, and zero to 2000 ppm, and the ranges for the CO₂ analyzer are zero to 5, zero to 10, and zero to 20%.

Specifications for the Carbon Monoxide and Carbon Dioxide Analyzers

Accuracy: 1% of full scale
Repeatability: + 0.5% of full scale
Zero drift: + 1% of full scale in 24 hours
Span drift: + 1% of full scale in 24 hours
Response time: selectable - 90% of full scale in 0.5, 1.2, 3, or 5 seconds
Power requirements: 115 VAC $\pm$ 10%, 60 Hz
Warm up time: 30 minutes
Output: 0-10 MV

Oxygen

A Beckman Model 742 oxygen analyzer was used to continuously determine the oxygen content of the flue gas sample. The oxygen measuring element contains a silver anode and gold cathode that are protected from the sample by a thin membrane of Teflon. An aqueous KCL solution is retained in the sensor by the membrane and serves as an electrolytic agent. As Teflon is permeable to gases, oxygen will diffuse from the sample to the cathode in the following oxidation-reduction reaction:

Cathode reaction: $O_2 + 2H_2O + 4e^- \rightarrow 4OH^-$

Anode reaction: $4Ag + 4Cl^- \rightarrow 4AgCl + 4e^-$

With an applied potential between the cathode and anode, oxygen will be reduced at the cathode causing a current to flow. The magnitude of this current is proportional to the partial pressure of oxygen present in the sample. The instrument has operating ranges of zero to 1%, zero to 10%, and zero to 25% oxygen.

Specifications for the Oxygen Analyzer

Accuracy: $\pm$ 1% of full scale or $\pm$ 0.05% O₂, whichever is greater
Sensor stability: $\pm$ 1% of full scale per 24 hours
Response time: 90% in 20 seconds
Output: 0-10 MV
Power requirements: 120/110 VAC, 60 Hz

Data Recording

The measurements from the gaseous analyzers were continuously recorded on dual-pen strip chart recorders, an automatic data logger and magnetic tape cassettes. These instruments are described in the following paragraphs:

o Strip-Chart Recorders

Three dual-pen Linear Instruments Corp. Model 432 strip chart recorders were installed in the continuous monitor. Two recorders were used to record the analyzer outputs and the third recorder was used as a back-up.

Specifications for the Strip-Chart Recorders

Recorder type: Null balance DC Servo
Input span: Base span 1 mV to 100 VDC
Accuracy: ± 0.5 percent
Temperature stability: $1 \mu\text{V}/^\circ\text{C}$
Response: 0.5 sec over full 250 mm span
Zero: Right hand zero, 100% zero suppression
Chart drive: 12 speeds
Chart width: Two channel crossover: 250 mm
Dimensions: 17.8 cm (7") H x 44.5 cm (17.5") W x 30.5 cm (12") D
Power requirements: 115/230 VAC 60 Hz: <20 watts
Weight: 11.4 kg (25 lb)

o Automatic Data Logger

The analyzer outputs were continuously recorded on a Monitor Lab Model 9300 microprocessor-based data logger. This data logger has the capability of recording 40 input channels. The data for each analyzer was printed, along with the exact time and date, in a digital form on a built-in inkless printer. The data logger was programmed to sample each analyzer every 4 seconds and print out averages every 15 minutes. The digital printout lists the number of samples in each averaging period.

Specifications for the Automatic Data Logger

Inputs: Up to 40 channels of analog voltage, current and temperature inputs can be accommodated in the mainframe.
Voltage ranges: $\pm 30,000 \text{ mV}$, $\pm 300.00 \text{ mV}$, $\pm 3.000 \text{ V}$, $\pm 12.000 \text{ V}$, Autorange
Resolution: $1 \mu\text{V}$ on 30,000 mV range
Accuracy: $\pm 0.02\%$ Reading $\pm 0.01\%$ range ± 1 digit
Power: 115/230 V $\pm 10\%$, 60 Hz, <125 watts
Dimensions: 18 cm (H) x 48.3 cm (W) x 56 cm (D) (17" x 19" x 22")
Weight: 18.2 kg (40 lb)

o Digital Tape Cassette Recorder

Data from the automatic data logger were recorded on magnetic tape cassettes with a Techtran Model 816 recorder. This recorder stored all gaseous emissions data on tape for subsequent use.

Specifications for the Tape Cassette Recorder

Storage capacity: 145,000 characters per cassette
Storage media: Phillips-type magnetic tape cassette
Tape speed: 20 ips read/write; 120 ips rewind
Size: 13 cm (H) x 18 cm (W) x 28 cm (D) (5" x 7-1/4" x 11")
Weight: 2.7 kg (6 lb)
Temperature range: 10° to 40°C
Power requirements: 115 VAC 47-63 Hz; 30 watts

Gaseous emissions data were measured continuously and recorded on an automatic data logger, as well as on strip-chart recorders and a magnetic tape recorder as already described. All gaseous emissions measurements were made and reported on a dry basis. Fifteen minute averages (about 225 data points for each instrument) of NO, O₂, CO₂, and CO emissions were recorded on tape, while strip-chart records were used to verify the data logger tapes and to fill in any gaps in the data from the automatic data logger. A daily log of emissions and boiler operating data was kept by a technician on-site. These data were later fed to a computer for data analysis.

The Conversion of NO_x units from ppm to ng/J was made using the procedure outlined in the Federal Register (Vol. 44, No. 113/Monday, June 11, 1979, paragraph 5.3, "Calculation of Emission Rate"). The NO emission rates for this unit were calculated from the following equation:

$$E = (C_d)(F_d) \frac{20.9}{20.9 - \% O_2}$$

Where:

E = pollutant emission rate, ng/J

C_d = pollutant concentration, ng/scm

To convert from ppm (NO_x) to ng/scm, multiply by 1.912 x 10⁶.

F_d = fuel firing factor (i.e., the ratio of gas volume released during combustion divided by the heat content of the fuel) dscm/J. F_d for bituminous coal is 2.63 x 10⁻⁷ dscm/J.

The subscript d represents a dry measurement of gaseous concentration.

NO emissions were measured on a dry basis and the emission rates reported herein were calculated based on the molecular weight of NO₂ (NO_x as NO₂). The boiler steam load is tabulated in units of thermal megawatts (the SI equivalent of Btu/hr). Thermal megawatts (MW_{TH}) were calculated by multiplying the boiler steam flow, lb/hr (obtained from the daily log sheet) by the enthalpy of the steam (approximately 10³ Btu/lb) and by the conversion factor for Btu/hr to watts, 0.293. Note that megawatts thermal is the

boiler steam load in SI energy units, and should not be confused with the gross electrical generator output which is also expressed in megawatts.

After the preliminary screening, the data were fed to the computer and a listing of 15-minute averages was compiled. Each 15-minute average was corrected to 3 percent O₂ basis and these data were then used to compile 24-hour averages for the entire test period. A partial listing of the 15-minute averages may be found at the end of this appendix.

CONTINUOUS MONITOR CERTIFICATION TESTS

Following shipment to the test site, the monitoring system was installed and certification tests were performed according to EPA's Performance Specification 2 (PS2) and 3 (PS3), 40 CFR 60. These specifications establish minimum performance criteria that the NO monitoring system must meet in terms of eight parameters: accuracy, calibration error, two- and 24-hour zero drifts, two- and 24-hour calibration drifts, response time, and operational period.

For the first test, the continuous monitor system was installed and instruments were initially calibrated on January 16, 1981. For the second test, the corresponding date was February 25, 1981. Both tests, however, were interrupted occasionally by plant upsets as explained in the main body of this report. This is why some days have no data recorded. Schedules of daily events for the certification tests are presented in Tables GG-2 and GG-3.

Certified calibration gases were obtained from Scott Environmental Technology, Inc. The calibration gases included zero gas as well as 50% and 90% (of full scale) span gases for the NO, CO₂, CO, and O₂ analyzers. In addition to the certified analysis supplied by the vendor, flask samples of the NO calibration gas were sent to an independent laboratory for analysis.

Relative accuracy tests for the NO analyzer were performed as outlined in PS2 using EPA Reference Method 7 (phenoldisulfonic acid [PDS] colorimetric) as the standard. Generally, nine sets of three PDS flasks (27 in all) were collected at one hour intervals during short periods within the 30-day tests. All sample flasks were returned to an independent laboratory for analysis. The NO_x span gases (various blends of NO in N₂) were also analyzed by the PDS method. The results of the relative accuracy determination showed that the NO instrument exceeded the accuracy requirements of PS2.

During these tests, the researchers noticed that the PDS analyses give consistently higher NO_x values than did the NO monitor. This is primarily due to two factors. First, the PDS analyses report NO_x as a combination of both NO and NO₂, while the monitor reports only NO. However, monitoring NO₂ (<5% of the total NO_x in most boilers) requires heated sample lines to prevent water condensation (since NO₂ is soluble in condensed water). The added cost and complexity needed to measure the small amount of NO₂ expected, was determined to be unnecessary and only NO was measured by the monitor.

TABLE GG-2. SCHEDULE OF CERTIFICATION TEST EVENTS

Date	Time	Event
1-21-81	0900	Initial 24 hour zero and span reading Initial 2 hour zero and span reading
1-21-81	1100	1st 2 hour zero and span drift point
1-21-81	1300	2nd 2 hour zero and span drift point
1-21-81	1500	3rd 2 hour zero and span drift point
1-22-81	0900	1st 24 hour zero and calibration drift point Initial 2 hour zero and calibration reading
1-22-81	1100	4th 2 hour zero and span drift point
1-22-81	1300	5th 2 hour zero and span drift point
1-22-81	1500	6th 2 hour zero and span drift point
1-23-81	0900	2nd 24 hour zero and calibration drift point Initial 2 hour zero and calibration reading
1-23-81	1100	7th 2 hour zero and calibration drift point
1-23-81	1300	8th 2 hour zero and calibration drift point
1-23-81	1500	9th 2 hour zero and calibration drift point
1-24-81	0900	3rd 24 hour zero and calibration drift point Initial 2 hour zero and calibration reading
1-24-81	1100	10th 2 hour zero and calibration drift point
1-24-81	1300	11th 2 hour zero and calibration drift point
1-24-81	1500	12th 2 hour zero and calibration drift point
1-25-81	0900	4th 24 hour zero and calibration drift point
1-25-81	1000	Initial 2 hour zero and calibration reading
1-25-81	1200	13th 2 hour zero and calibration drift point
1-25-81	1400	14th 2 hour zero and calibration drift point
1-25-81	1600	15th 2 hour zero and calibration drift point
1-26-81	0900	5th 24 hour zero and calibration drift point
1-27-81	0900	6th 24 hour zero and calibration drift point
1-28-81	0900	7th and final 24 hour zero and calibration drift point
1-28-81	0900	Instrument Response time sheets
1-28-81	0900	1st set of relative accuracy samples taken
1-28-81	1000	2nd set of relative accuracy samples taken
1-28-81	1100	3rd set of relative accuracy samples taken
1-28-81	1300	4th set of relative accuracy samples taken
1-28-81	1400	5th set of relative accuracy samples taken
1-28-81	1500	6th set of relative accuracy samples taken
1-28-80	1600	7th set of relative accuracy samples taken
1-28-81	1700	8th set of relative accuracy samples taken

TABLE GG-3. SCHEDULE OF CERTIFICATION TEST EVENTS.

Date	Time	Event
3-23-81	0900	Initial 2 hour zero and span reading
3-23-81	1100	1st 2 hour zero and span drift point
3-23-81	1300	2nd 2 hour zero and span drift point
3-23-81	1500	3rd 2 hour zero and span drift point
3-24-81	0900	Initial 2 hour zero and calibration reading
3-24-81	1100	4th 2 hour zero and span drift point
3-24-81	1300	5th 2 hour zero and span drift point
3-24-81	1500	6th 2 hour zero and span drift point
3-25-81	0900	Initial 2 hour zero and calibration reading
3-25-81	1100	7th 2 hour zero and calibration drift point
3-25-81	1300	8th 2 hour zero and calibration drift point
3-25-81	1500	9th 2 hour zero and calibration drift point
3-25-81	0900	1st set of relative accuracy samples taken
3-25-81	1000	2nd set of relative accuracy samples taken
3-25-81	1100	3rd set of relative accuracy samples taken
3-25-81	1300	4th set of relative accuracy samples taken
3-25-81	1400	5th set of relative accuracy samples taken
3-25-81	1500	6th set of relative accuracy samples taken
3-25-81	1600	7th set of relative accuracy samples taken
3-25-81	1700	8th set of relative accuracy samples taken
3-26-81	0900	Initial 2 hour zero and calibration reading
3-26-81	1100	10th 2 hour zero and calibration drift point
3-26-81	1300	11th 2 hour zero and calibration drift point
3-26-81	1500	12th 2 hour zero and calibration drift point
3-26-81	0900	Instrument response time sheets
3-27-81	1000	Initial 2 hour zero and calibration reading
3-27-81	1200	13th 2 hour zero and calibration drift point
3-27-81	1400	14th 2 hour zero and calibration drift point
3-27-81	1600	15th 2 hour zero and calibration drift point
4-1-81	0900	Initial 24 hour and span reading
4-2-81	0900	1st 24 hour zero and calibration drift point
4-3-81	0900	2nd 24 hour zero and calibration drift point
4-4-81	0900	3rd 24 hour zero and calibration drift point
4-5-81	0900	4th 24 hour zero and calibration drift point
4-6-81	0900	5th 24 hour zero and calibration drift point
4-7-81	0900	6th 24 hour zero and calibration drift point
4-8-81	0900	7th and final 24 hour zero and calibration drift point

(ok)

The other factor contributing to the discrepancy was probably the span gas mixture. The mixture used for this test was NO mixed with N₂ as specified in the Federal Register. KVB has conducted tests that show that when CO₂ is present in the gas being monitored (as it is in the flue gas), the CO₂ will interfere slightly with the accuracy of the NO_x monitor due to third body quenching unless a similar amount of CO₂ is also present in the calibration gas. The NO_x error could be 8% when the gas being monitored contains 10% CO₂. Nevertheless, all relative accuracy tests showed that the NO instrument exceeded the accuracy requirements of PS2.

THEORETICAL COMBUSTION PRODUCTS BASED ON COAL ANALYSIS

During Test No. 1, samples of the coal were taken and submitted by KVB, to an independent laboratory for analysis. The results of these fuel analyses (presented in Table GG-4) were used to calculate theoretical combustion information.

REFERENCES FOR THIS APPENDIX

1. Maloney, K. L. et al., "Systems Evaluation of the Use of Low-Sulfur Western Coal in Existing Small and Intermediate-Sized Boilers," EPA Contract No. 68-02-1863, EPA 600/7-78-153a.
2. Cato, G. A. et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase I," EPA 650/2-74-078a, NTIS No. PB 238 920, June 1975.
3. Cato, G. A. et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase II," EPA 600/2-76-086a, NTIS No. PB 253 500, April 1976.

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TABLE GG-4. Test No. 1: SUMMARY OF FUEL ANALYSES FOR LOUISVILLE
GAS & ELECTRIC, MILL CREEK UNIT 3.

Ultimate Analysis	January 18, 1981		February 20, 1981	
	As Received	Dry Basis	As Received	Dry Basis
% Moisture	8.43	xxxxx	9.43	xxxxx
% Carbon	65.83	71.89	64.22	70.91
% Hydrogen	4.65	5.08	4.47	4.93
% Nitrogen	1.14	1.25	1.29	1.42
% Chlorine	0.05	0.06	0.05	0.06
% Sulfur	4.04	4.41	3.74	4.13
% Ash	9.63	10.52	10.42	11.51
% Oxygen (diff)	6.23	6.79	6.38	7.04
	100.00	100.00	100.00	100.00
Btu/lb.	11963	13064	11703	12922

TABULATION OF 15-MINUTE CEM DATA

SELECTED DATA FROM
TEST NO. 2

As an example, the next few pages present data
from about two days of the second thirty day test.

15 MIN. DATA
DRY STACK GAS CONCENTRATION

DATE	TIME	LOAD MWH	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV MEAS	CO PPMV 3XO2	NO PPMV 3XO2	CO NG/J	NO NG/J
** 4/17/81	15	680.1	5.3	12.2	54	321	61	368	22	216
** 4/17/81	30	680.1	5.6	12.0	53	323	62	377	22	221
** 4/17/81	45	559.9	6.1	11.4	53	297	64	359	22	210
** 4/17/81	100	559.9	6.3	11.4	55	293	67	359	24	210
** 4/17/81	130	503.1	6.2	11.4	55	296	66	360	23	211
** 4/17/81	145	503.1	6.3	11.4	55	297	67	360	24	213
** 4/17/81	200	503.1	6.3	11.4	55	298	67	365	24	214
** 4/17/81	215	500.7	6.3	11.3	56	295	68	361	24	212
** 4/17/81	230	500.7	6.3	11.3	57	294	69	360	24	211
** 4/17/81	245	500.7	6.3	11.3	56	297	68	364	24	213
** 4/17/81	300	500.7	6.2	11.4	56	298	68	362	24	213
** 4/17/81	315	500.7	6.2	11.3	56	296	68	360	24	211
** 4/17/81	330	500.7	6.2	11.3	57	295	69	359	24	210
** 4/17/81	345	497.5	6.2	11.4	59	297	71	361	25	212
** 4/17/81	400	497.5	6.0	11.6	9	311	10	373	3	219
** 4/17/81	415	497.5	5.8	11.7	9	318	10	376	3	221
** 4/17/81	430	495.8	5.5	11.9	10	330	11	383	4	225
** 4/17/81	445	495.8	5.3	12.1	10	338	11	387	4	227
** 4/17/81	500	495.8	5.0	12.3	14	347	15	390	5	229
** 4/17/81	515	495.8	4.8	12.4	10	361	11	401	3	235
** 4/17/81	530	495.8	4.8	12.5	9	370	9	408	3	240
** 4/17/81	545	497.2	4.7	12.6	11	366	12	404	4	237
** 4/17/81	600	497.2	4.8	12.5	10	365	11	405	6	238
** 4/17/81	615	497.2	4.8	12.5	10	365	11	405	3	238
** 4/17/81	630	497.2	4.7	12.6	10	361	11	398	3	234
** 4/17/81	645	581.0	4.6	12.6	24	364	30	399	10	234
No Readings While Recalibrating										
** 4/17/81	700	581.0	4.3	10.0	17	331	18	356	6	200
** 4/17/81	715	581.0	4.5	12.9	17	371	18	404	3	241
** 4/17/81	730	581.0	4.6	12.9	19	370	20	406	7	240
** 4/17/81	745	706.4	4.6	12.9	26	373	28	409	10	240
** 4/17/81	760	706.4	4.6	12.9	10	372	10	408	3	239

***** 15 MIN. DATA *****											
***** DRY STACK GAS CONCENTRATION *****											
DATE	TIME	LOAD MWH	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV MEAS	CO PPMV 3XO2	NO PPMV 3XO2	CO NG/J	NO NG/J	
** 4/17/81	1215	766.5	4.5	12.9	12	371	13	404	4	237	**
** 4/17/81	1230	766.5	4.4	13.0	14	374	15	405	5	238	**
** 4/17/81	1245	771.8	4.5	12.9	18	378	19	412	7	242	**
** 4/17/81	1300	771.8	4.4	13.0	11	371	11	402	4	236	**
** 4/17/81	1315	771.8	4.5	12.9	15	373	16	407	5	239	**
** 4/17/81	1330	771.8	4.3	13.1	12	368	12	392	4	230	**
** 4/17/81	1345	768.8	4.4	13.0	23	369	24	400	8	235	**
** 4/17/81	1400	768.8	4.4	13.0	15	368	16	399	5	234	**
** 4/17/81	1415	768.8	4.4	12.9	10	372	10	403	3	236	**
** 4/17/81	1430	768.8	4.4	13.0	11	370	11	401	4	235	**
** 4/17/81	1445	775.3	4.4	12.9	25	369	27	400	9	235	**
** 4/17/81	1500	775.3	4.4	12.9	25	370	27	401	9	235	**
** 4/17/81	1515	775.3	4.5	12.9	20	369	21	402	7	236	**
** 4/17/81	1530	775.3	4.5	12.9	20	369	21	402	7	236	**
** 4/17/81	1545	771.5	4.5	12.8	20	370	21	403	7	237	**
** 4/17/81	1600	771.5	4.5	12.9	22	366	24	399	8	234	**
** 4/17/81	1615	771.5	4.5	12.8	26	366	28	399	10	234	**
** 4/17/81	1630	771.5	4.5	12.9	22	367	24	400	8	235	**
** 4/17/81	1645	770.6	4.5	12.8	22	370	24	403	8	237	**
** 4/17/81	1700	770.6	4.5	12.8	22	369	24	402	8	236	**
** 4/17/81	1715	770.6	4.5	12.9	18	369	19	402	7	236	**
** 4/17/81	1730	770.6	4.5	12.9	18	370	19	403	7	237	**
** 4/17/81	1745	768.0	4.5	12.8	14	371	15	404	5	237	**
** 4/17/81	1800	768.0	4.5	12.9	14	367	15	400	5	235	**
** 4/17/81	1815	768.0	4.5	12.8	17	368	18	401	6	235	**
** 4/17/81	1830	768.0	4.5	12.8	19	367	20	400	7	235	**
** 4/17/81	1845	770.9	4.5	12.9	18	370	19	403	7	237	**
** 4/17/81	1900	770.9	4.5	12.8	24	367	26	400	9	235	**
** 4/17/81	1915	770.9	4.5	12.9	27	362	29	395	10	231	**
** 4/17/81	1930	770.9	4.5	12.8	20	367	21	400	7	235	**
** 4/17/81	1945	773.2	4.5	12.8	24	369	26	402	9	236	**
** 4/17/81	2000	773.2	4.4	12.9	20	368	21	399	7	234	**
** 4/17/81	2015	773.2	4.4	12.9	27	372	29	403	10	236	**
** 4/17/81	2030	773.2	4.3	13.0	23	367	24	395	8	232	**
** 4/17/81	2045	772.6	4.4	12.9	22	369	23	400	8	235	**
** 4/17/81	2100	772.6	4.4	12.9	26	365	28	395	10	232	**
** 4/17/81	2115	772.6	4.5	12.8	23	371	25	404	8	237	**
** 4/17/81	2130	772.6	4.5	12.8	25	371	27	404	9	237	**
** 4/17/81	2145	766.2	4.4	12.9	24	372	26	403	9	236	**
** 4/17/81	2200	766.2	4.4	12.9	24	371	26	402	9	236	**
** 4/17/81	2215	766.2	4.5	12.8	22	371	24	404	8	237	**
** 4/17/81	2230	766.2	4.6	12.8	13	372	14	408	5	239	**
** 4/17/81	2245	770.9	4.6	12.8	14	375	15	411	5	241	**
** 4/17/81	2300	770.9	4.5	12.8	15	374	16	408	5	239	**
** 4/17/81	2315	770.9	4.7	12.7	14	378	15	417	5	245	**
** 4/17/81	2330	770.9	4.6	12.8	14	369	15	405	5	237	**
** 4/17/81	2345	703.5	4.8	12.6	13	355	14	394	5	231	**
** 4/17/81	2400	703.5	5.1	12.4	12	340	13	385	4	228	**

15 MIN. DATA
DRY STACK GAS CONCENTRATION

DATE	TIME	LOAD MWH	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV MEAS	CO PPMV 3XO2	NO PPMV 3XO2	CO NG/J	NO NG/J
** 4/18/81	15	703.5	5.9	11.7	41	297	48	354	17	208
** 4/18/81	30	703.5	8.1	9.5	42	260	58	363	20	213
** 4/18/81	45	353.7	9.5	8.3	44	234	69	367	24	215
** 4/18/81	100	353.7	9.5	8.1	44	229	69	359	24	211
** 4/18/81	115	353.7	9.5	8.2	44	235	69	368	24	216
** 4/18/81	130	353.7	9.6	8.0	45	229	71	362	25	212
** 4/18/81	145	274.2	9.4	8.2	45	233	70	362	25	212
** 4/18/81	200	274.2	9.2	8.5	44	240	67	367	24	215
** 4/18/81	215	274.2	9.1	8.5	44	237	66	359	23	211
** 4/18/81	230	274.2	9.1	8.6	44	238	66	361	23	211
** 4/18/81	245	271.6	9.1	8.6	45	235	68	356	24	209
** 4/18/81	300	271.6	9.1	8.6	46	235	69	356	24	209
** 4/18/81	315	271.6	9.1	8.6	47	235	71	356	25	209
** 4/18/81	330	271.6	9.1	8.5	47	234	71	354	25	208
** 4/18/81	345	272.8	9.2	8.5	48	235	73	359	26	211
** 4/18/81	400	272.8	9.1	8.6	47	236	71	357	25	210
** 4/18/81	415	272.8	9.1	8.6	47	236	71	357	25	210
** 4/18/81	430	272.8	9.1	8.7	47	237	71	359	25	211
** 4/18/81	445	276.6	9.1	8.7	48	237	72	359	26	211
** 4/18/81	500	276.6	9.1	8.7	48	238	72	361	26	211
** 4/18/81	515	276.6	9.1	8.6	49	237	74	359	26	211
** 4/18/81	530	276.6	9.1	8.7	30	239	45	362	16	212
** 4/18/81	545	275.1	9.0	8.7	30	241	45	362	16	212
** 4/18/81	600	275.1	9.0	8.7	30	240	45	361	16	211
** 4/18/81	615	275.1	9.1	8.7	30	239	45	362	16	212
** 4/18/81	630	275.1	9.2	8.4	32	231	48	353	17	207
** 4/18/81	645	255.5	11.1	5.8	27	184	49	336	17	197
** 4/18/81	700	255.5	10.3	6.9	27	206	45	347	16	204
** 4/18/81	715	255.5	10.4	6.8	28	193	47	329	17	193
** 4/18/81	730	255.5	10.6	6.5	32	194	55	337	19	197
** 4/18/81	745	265.5	10.5	6.7	33	195	56	335	20	197
** 4/18/81	800	265.5	10.4	6.8	33	197	56	335	20	197
No Readings While-Recalibrating										
** 4/18/81	830	265.5	5.0	3.7	12	216	13	243	4	142
** 4/18/81	845	269.6	10.4	7.0	42	199	71	339	25	199
** 4/18/81	900	269.6	10.4	7.1	42	198	71	337	25	198
** 4/18/81	915	269.6	10.4	7.0	44	197	75	335	26	197
** 4/18/81	930	269.6	10.3	7.1	43	198	72	334	25	196
** 4/18/81	945	269.6	10.2	7.1	43	199	71	332	25	195
** 4/18/81	1000	269.0	10.2	7.1	43	200	71	334	25	196
** 4/18/81	1015	269.0	10.2	7.1	42	201	70	336	25	197
** 4/18/81	1030	269.0	10.2	7.1	41	206	68	334	24	196
** 4/18/81	1045	294.5	10.1	7.2	40	200	66	331	23	194
** 4/18/81	1100	294.5	9.4	8.2	38	225	59	350	21	205
** 4/18/81	1115	294.5	7.7	10.1	35	267	47	362	14	212
** 4/18/81	1130	294.5	8.1	9.8	36	280	50	391	17	229
** 4/18/81	1145	454.4	6.1	11.6	37	293	44	354	15	208
** 4/18/81	1200	454.4	5.9	11.9	37	314	44	374	15	220

***** 15 MIN. DATA *****											
***** DRY STACK GAS CONCENTRATION *****											
DATE	TIME	LOAD MWH	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV MEAS	CO PPMV 3XO2	NO PPMV 3XO2	CO NG/J	NO NG/J	
** 4/18/81	1215	454.4	5.5	12.2	37	319	43	370	15	217	
** 4/18/81	1230	454.4	5.3	12.4	37	340	42	390	15	229	
** 4/18/81	1245	598.9	5.4	12.3	37	337	42	389	15	228	
** 4/18/81	1300	598.9	5.5	12.3	37	339	43	394	15	231	
** 4/18/81	1315	598.9	5.5	12.2	37	339	43	394	15	231	
** 4/18/81	1330	598.9	5.5	12.2	38	339	44	394	15	231	
** 4/18/81	1345	598.9	5.5	12.2	38	339	44	394	15	231	
** 4/18/81	1400	598.9	5.5	12.2	39	341	45	396	16	232	
** 4/18/81	1415	598.9	5.4	12.3	40	350	46	404	16	237	
** 4/18/81	1430	598.9	5.2	12.4	41	392	46	446	16	262	
** 4/18/81	1445	729.0	5.3	12.3	40	405	45	464	16	272	
** 4/18/81	1500	729.0	5.4	12.3	39	404	45	466	16	273	
** 4/18/81	1515	729.0	5.3	12.3	39	399	44	457	15	268	
** 4/18/81	1530	729.0	5.2	12.4	40	398	45	453	16	266	
** 4/18/81	1545	766.8	5.3	12.4	40	399	45	457	16	268	
** 4/18/81	1600	766.8	5.3	12.3	41	400	47	458	16	269	
** 4/18/81	1615	766.8	5.4	12.3	41	400	47	461	16	271	
** 4/18/81	1630	766.8	5.3	12.3	42	401	48	460	17	270	
** 4/18/81	1645	766.5	5.3	12.4	42	400	48	458	17	269	
** 4/18/81	1700	766.5	5.3	12.4	41	400	47	458	16	269	
** 4/18/81	1715	766.5	5.2	12.4	41	402	48	458	16	269	
** 4/18/81	1730	766.5	5.3	12.4	41	401	47	460	16	270	
** 4/18/81	1745	766.2	5.3	12.3	41	401	47	460	16	270	
** 4/18/81	1800	766.2	5.4	12.4	42	392	47	425	17	249	
** 4/18/81	1815	766.2	5.4	12.1	41	388	47	448	16	263	
** 4/18/81	1830	766.2	6.2	11.6	42	356	51	433	18	254	
** 4/18/81	1845	747.7	5.7	12.0	43	381	50	448	18	263	
** 4/18/81	1900	747.7	5.7	12.1	43	377	50	443	18	260	
** 4/18/81	1915	747.7	5.8	11.9	43	388	50	459	18	270	
** 4/18/81	1930	747.7	5.8	12.0	43	394	50	467	18	274	
** 4/18/81	1945	758.9	5.7	12.0	43	399	50	469	18	275	
** 4/18/81	2000	758.9	5.8	11.9	43	401	50	475	18	279	
** 4/18/81	2015	758.9	5.8	12.0	44	396	52	464	18	275	
** 4/18/81	2030	758.9	5.8	12.0	45	399	53	472	19	277	
** 4/18/81	2045	754.8	5.7	12.0	45	397	52	467	18	274	
** 4/18/81	2100	754.8	5.6	12.0	46	402	54	476	19	279	
** 4/18/81	2115	754.8	5.7	12.0	47	398	55	468	19	275	
** 4/18/81	2130	754.8	5.7	12.1	46	390	54	459	19	269	
** 4/18/81	2145	760.9	5.7	12.0	46	392	54	461	19	271	
** 4/18/81	2200	760.9	5.7	12.1	46	384	54	452	19	265	
** 4/18/81	2215	760.9	5.7	12.1	46	386	54	454	19	266	
** 4/18/81	2230	760.9	5.7	12.1	47	385	55	453	19	266	
** 4/18/81	2245	751.8	5.8	12.0	47	373	55	442	19	259	
** 4/18/81	2300	751.8	5.7	12.0	48	379	56	446	20	262	
** 4/18/81	2315	751.8	5.8	12.0	49	372	58	440	20	258	
** 4/18/81	2330	751.8	5.9	11.9	49	358	58	427	20	250	
** 4/18/81	2345	670.7	6.0	11.9	48	338	57	406	20	238	
** 4/18/81	2400	670.7	5.8	11.9	48	332	57	396	20	232	

15 MIN. DATA
DRY STACK GAS CONCENTRATION

DATE	TIME	LOAD MWH	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV MEAS	CO PPMV 3XO2	NO PPMV 3XO2	CO NG/J	NO NG/J
** 4/19/81	15	670.7	5.8	12.0	28	318	33	376	11	221
** 4/19/81	30	670.7	6.0	11.8	28	316	33	379	12	222
** 4/19/81	45	552.0	6.4	11.3	29	311	35	381	12	223
** 4/19/81	100	552.0	6.6	11.3	29	297	36	371	12	218
** 4/19/81	115	552.0	6.8	11.2	30	292	38	370	13	217
** 4/19/81	130	492.2	6.8	11.1	31	289	39	368	14	215
** 4/19/81	145	492.2	6.8	11.1	31	291	39	369	14	216
** 4/19/81	200	492.2	6.8	11.1	30	288	38	365	13	214
** 4/19/81	215	492.2	6.8	11.1	30	287	38	364	13	213
** 4/19/81	230	492.2	6.8	11.1	30	287	38	364	13	213
** 4/19/81	245	494.6	6.8	11.1	30	289	38	366	13	215
** 4/19/81	300	494.6	6.8	11.4	31	289	38	356	13	209
** 4/19/81	315	494.6	6.4	11.4	32	322	39	397	14	233
** 4/19/81	330	494.6	6.5	11.4	32	331	39	411	14	241
** 4/19/81	345	473.5	7.1	10.7	34	329	44	426	15	250
** 4/19/81	400	473.5	7.1	10.8	35	337	45	437	16	256
** 4/19/81	415	473.5	6.6	11.2	34	355	42	444	15	260
** 4/19/81	430	473.5	6.7	11.2	34	361	42	459	15	267
** 4/19/81	445	467.3	6.6	11.3	33	355	41	444	14	260
** 4/19/81	500	467.3	6.6	11.3	32	351	40	439	14	257
** 4/19/81	515	467.3	6.5	11.3	34	354	42	440	15	258
** 4/19/81	530	467.3	6.5	11.3	34	348	42	432	15	253
** 4/19/81	545	458.5	6.6	11.2	34	357	42	446	15	262
** 4/19/81	600	458.5	6.5	11.3	36	356	44	442	15	259
** 4/19/81	615	458.5	6.9	10.9	37	329	47	420	16	246
** 4/19/81	630	458.5	7.3	10.6	36	317	47	417	16	244
** 4/19/81	645	419.3	7.4	10.5	37	316	49	418	17	246
** 4/19/81	700	419.3	7.4	10.5	36	324	47	429	17	252
** 4/19/81	715	419.3	6.8	11.0	35	329	44	417	15	245
** 4/19/81	730	419.3	6.8	11.0	35	328	44	416	15	244
** 4/19/81	745	448.6	6.7	11.1	36	338	45	426	16	250
** 4/19/81	800	448.6	6.5	11.3	36	341	44	423	15	248
** 4/19/81	815	448.6	6.5	11.3	37	344	45	427	16	251
** 4/19/81	830	448.6	6.7	11.1	37	342	46	431	16	253
** 4/19/81	845	476.7	6.5	11.3	35	326	43	405	15	237
** 4/19/81	900	476.7	5.8	11.9	35	325	41	385	14	226
** 4/19/81	915	476.7	5.3	12.3	38	335	43	384	15	225
** 4/19/81	930	476.7	5.1	12.5	38	347	43	393	15	230
** 4/19/81	945	602.1								
** 4/19/81	1000	602.1								
** 4/19/81	1015	602.1	4.8	12.7	39	355	43	394	15	231
** 4/19/81	1030	602.1	4.9	12.6	37	352	41	393	14	231
** 4/19/81	1045	613.5	5.0	12.6	37	350	41	394	14	231
** 4/19/81	1100	613.5	5.1	12.5	35	341	39	386	14	226
** 4/19/81	1115	613.5	5.1	12.4	35	341	39	386	14	226
** 4/19/81	1130	613.5	5.0	12.5	40	341	45	383	16	225
** 4/19/81	1145	605.0	4.9	12.6	35	349	39	390	13	229
** 4/19/81	1200	605.0	5.0	12.6	36	347	40	390	14	229

No Readings While Recalibrating

***** 15 MIN. DATA *****											
***** DRY STACK GAS CONCENTRATION *****											
DATE	TIME	LOAD MWH	O ₂ VOL% MEAS	CO ₂ VOL% MEAS	CO PPMV MEAS	NO PPMV MEAS	CO PPMV 3XO ₂	NO PPMV 3XO ₂	CO NG/J	NO NG/J	
** 4/19/81	1215	605.0	5.1	12.5	35	348	39	394	14	231	
** 4/19/81	1230	605.0	5.0	12.5	36	346	40	389	14	228	
** 4/19/81	1245	615.9	5.0	12.5	37	345	41	388	14	228	
** 4/19/81	1300	615.9	5.0	12.5	37	348	41	391	14	230	
** 4/19/81	1315	615.9	5.0	12.6	36	348	40	391	14	230	
** 4/19/81	1330	615.9	4.9	12.6	35	344	39	384	13	225	
** 4/19/81	1345	609.1	5.0	12.5	35	343	39	386	14	226	
** 4/19/81	1400	609.1	5.0	12.5	36	339	40	381	14	224	
** 4/19/81	1415	609.1	4.9	12.6	36	337	40	377	14	221	
** 4/19/81	1430	609.1	4.9	12.6	37	337	41	377	14	221	
** 4/19/81	1445	590.4	4.9	12.6	37	334	41	373	14	219	
** 4/19/81	1500	590.4	5.0	12.5	36	331	40	370	14	217	
** 4/19/81	1515	590.4	5.0	12.5	36	331	40	372	14	218	
** 4/19/81	1530	590.4	5.1	12.4	35	330	39	373	14	219	
** 4/19/81	1545	574.6	5.0	12.5	34	331	38	372	13	218	
** 4/19/81	1600	574.6	5.0	12.4	34	336	38	374	13	220	
** 4/19/81	1615	574.6	5.0	12.5	34	333	38	374	13	220	
** 4/19/81	1630	574.6	4.9	12.5	35	335	39	374	13	220	
** 4/19/81	1645	586.3	4.9	12.5	34	334	38	373	13	219	
** 4/19/81	1700	586.3	4.9	12.5	36	336	40	375	14	220	
** 4/19/81	1715	586.3	5.2	12.2	34	317	38	361	13	212	
** 4/19/81	1730	586.3	5.3	12.2	33	316	37	362	13	212	
** 4/19/81	1745	527.1	5.3	12.2	33	316	37	362	13	212	
** 4/19/81	1800	527.1	5.3	12.2	32	318	36	363	13	213	
** 4/19/81	1815	527.1	5.3	12.2	32	317	36	362	13	212	
** 4/19/81	1830	527.1	5.3	12.3	32	316	36	362	13	212	
** 4/19/81	1845	540.3	5.3	12.2	32	318	36	364	13	214	
** 4/19/81	1900	540.3	5.2	12.3	33	317	37	361	13	212	
** 4/19/81	1915	540.3	5.1	12.3	34	327	38	370	13	217	
** 4/19/81	1930	540.3	5.0	12.4	36	331	40	372	14	218	
** 4/19/81	1945	624.7	5.0	12.5	36	338	40	380	14	223	
** 4/19/81	2000	624.7	4.9	12.5	35	348	39	389	13	228	
** 4/19/81	2015	624.7	4.9	12.5	34	348	38	400	13	235	
** 4/19/81	2030	624.7	4.9	12.5	35	360	39	402	13	236	
** 4/19/81	2045	698.2	4.9	12.5	35	364	39	407	13	239	
** 4/19/81	2100	698.2	4.8	12.6	39	371	43	412	15	242	
** 4/19/81	2115	698.2	4.8	12.6	37	362	41	402	14	236	
** 4/19/81	2130	698.2	4.8	12.6	36	348	40	386	14	227	
** 4/19/81	2145	670.1	4.7	12.7	39	337	43	372	15	218	
** 4/19/81	2200	670.1	4.7	12.7	39	331	43	365	15	214	
** 4/19/81	2215	670.1	4.7	12.7	39	327	43	361	15	212	
** 4/19/81	2230	670.1	4.8	12.6	36	323	40	359	14	210	
** 4/19/81	2245	609.7	5.0	12.4	35	319	39	359	14	210	
** 4/19/81	2300	609.7	5.1	12.4	35	304	39	344	14	210	
** 4/19/81	2315	609.7	5.2	12.3	34	310	38	353	14	207	
** 4/19/81	2330	609.7	5.2	12.3	34	313	38	356	13	209	
** 4/19/81	2345	560.2	5.3	12.2	34	308	39	353	13	207	
** 4/19/81	2400	560.2	5.3	12.1	34	304	38	348	13	204	

APPENDIX H
SASS* AND OTHER LEVEL 1 RESULTS

	<u>Page</u>
o Validity of cyclone cut points	210
o Sample volumes	211
o Laboratory report (selected sections)	213

*This appendix contains the essence of the SASS raw data and calculations which are too voluminous for complete inclusion.

Validity of Cyclone Cutpoints

At meter conditions (Dry - 0% H₂O, 5.7% O₂, T_{avg} = 111°F, P_{avg} = 29.4" Hg), 1044.2 ft³ (DACF) was sampled (see Table GH-2). This means that the actual quantity of (wet) gas that passed through the cyclones (at 6.2% H₂O, T_{avg} = 395°F, P_{avg} = 28.8" Hg) then was:

$$Q_{\text{cyclones}} = \left(\frac{1044.2}{1 - 0.062} \right) \left(\frac{460 + 395}{460 + 111} \right) \left(\frac{29.4}{28.8} \right) \\ = 1,702 \text{ ft}^3 \text{ (WACF)}$$

Since actual sampling time was 285 min, the average flow rate through the cyclones was 5.97 ACF/min. (The cyclone cut points are calibrated for 6.5 ACF/min.) Therefore, because sampling was about 8% slower than the design rate, the actual cut points of the three cyclones may have shifted slightly from their design points of 1, 3, and 10 μm, respectively. For the smallest cyclone, change is insignificant. However, for the two largest cyclones, a square root relationship with flow is expected. Therefore, instead of 1, 3, and 10 μm, the cutpoints were about 1, 3.5, and 12 μm, respectively.

Sampling occurred isokinetically (%I = 101.2), thus insuring that the sample was representative. Furthermore, subsequent morphological analysis by microscopy (discussed later in this appendix) revealed that the cyclones had performed well in separating the particles according to size.

TABLE GH-1
SASS SAMPLE SIZES
(Field Measurements*)

Volume of Gas Sampled (also, see next page)		1000 ft ³
1st Impinger (H ₂ O ₂)	500 mL	
Pre test		
Post test		
1st rinse		575 mL
Line rinse		225 mL
Shipped to Linden for Analysis		270 mL
		<u>1070 mL</u>
2nd Impinger (AgNO ₃ , etc.)	500 mL	
Pre test		
Post test		
1st rinse (by difference)		490 mL
Final rinse		335 mL
Shipped to Linden for Analysis		50 mL
		<u>875 mL</u>
3rd Impinger (AgNO ₃ , etc.)	500 mL	
Pre test		
Post test		
1st rinse (by difference)		500 mL
2nd rinse		115 mL
Final rinse		25 mL
Shipped to Linden for Analysis		80 mL
		<u>720 mL</u>
Organic Module - CH ₂ Cl ₂ Rinse		550 mL
Probe Rinse		2000 mL
4th Impinger (silica gel)	1st Batch	2nd Batch
Pre-test gross weight	2594 g	2480 g
Post test gross weight	<u>2861 g</u>	<u>2636 g</u>
Weight gain (H ₂ O)	221 g	156 g
(Pre-test weight of <u>dry</u> silica gel = 750 g in each batch.)		

*Other sample sizes are included in the laboratory report summarized on the following pages of this appendix.

TABLE GH-2

SASS OPERATING LOG SUMMARY AND EARLY CALCULATED RESULTS

Start Time	10-15-80	14:51
End Time	10-15-80	21:36
Elapsed Time		7:45
Sampling Time (probe actually in duct)		4:45
Gas Volume Sampled (actual volume at meter) (DACF at 111°F, 29.4" Hg, 5.7% O ₂ * does not consider leaks)		1044.2 ft ³
Gas Volume Sampled (corrected to standard conditions) (DSCF (0% H ₂ O) @ 20°C (68°F), and 29.92" Hg (1 Atm), 5.7% O ₂)		949 ft ³
Avg. Stack Temp. Nozzle Size		305.2°F 5/8 in. (dia)
Velocity Head (Pitot Tube Readings) (ΔP) avg. ($\sqrt{\Delta P}$) avg. Stack velocity (single point test avg.)		0.361 in H ₂ O 0.601 41.4* ft/sec
Percent of isokinetic rate (a post test calculation that does not consider leaks)		101.2
Initial Leak Rate Through organic module @ >5" Hg vacuum Entire train @ >20" Hg vacuum Final Leak Rate Entire train @ 8.5" Hg vacuum Through organic module @ 12" Hg vacuum		<0.05 ft ³ /min <0.05 ft ³ /min 0.48 ft ³ /min 0.061 ft ³ /min
Percent H ₂ O in the duct (a post test calculation that does not consider leaks)		6.2%***

*From Entropy's Method 5 report (Appendix F).

**Average stack velocity by Method 5 = 41.5 ft/sec. (See Appendix F for Method 5 report.)

(The SASS method gives an average of many readings at a single point, while Method 5 gives an average of many single readings at many points).

***Entropy's Method 5 results give water concentration as 7.07 vol % at the ESP inlet.

LABORATORY REPORT (LEVEL 1 TEST)

1.0 Summary

Stack emission samples collected from a coal-fired utility boiler were analyzed for inorganic and organic constituents. A SASS train sampling device was used to collect emissions from a Louisville power plant. The nominal flue gas volume sampled was 30 m³. As part of the EPA Level 1 study, microscopy and metal analyses were performed on the particulates. Quantities of extractable organics were measured and where sufficient amounts existed, more detailed functional group characterizations were performed.

Extractable organics were 129 mg for the Louisville test. The majority (>90%) of these compounds were found on the XAD-2 organic adsorbent resin. GC/MS and FTIR analyses of certain sample extracts identified low levels of aliphatic acids, and alkyl esters. Dimethyl sulfate, a suspected carcinogen, was identified by GC/MS analysis of the Louisville stack emissions. Although dimethyl sulfate may have been an emission, it is also possible that this compound was generated as an artifact of this EPA Level 1 scheme used in separating organic classes.

Scanning electron microscopy performed on the particulates generally showed good size fractionation in the SASS 10, 3, and 1µm cyclones although some <3µm particles were in the 10 and 3µm cyclones.

Inductively Coupled Plasma Emission Spectroscopy (ICPES) metal analysis showed that most metals had generally higher g/g concentrations on the smaller particulates. However, less than 5% of the total metal emissions were collected in the 1 micron cyclone. In general, the levels of most toxic metals were low (<100 mg/SASS test) and near the ICPES detection limits.

2.0 Introduction

In September and October, 1980, an Exxon sampling team collected stack emission samples from two high sulfur coal combustion utility boilers. One objective of the EPA sponsored study (contract number EPA-68-02-2696) was to determine if toxic materials are being emitted. This report presents analytical results on inorganic and organic emissions from the Mill Creek generating station, Louisville, Kentucky, designed to burn high sulfur coal with minimum NO_x emissions.

3.0 Sampling and Analysis

Stack emission samples were collected using the SASS (Source Assessment Sampling System). A diagram detailing the various components of the system is illustrated in Figure C-II-2 in the main body of this report.

Flue gases first pass through a heated stainless steel probe and then into an oven. Both the probe and oven were maintained at 400°F to prevent condensation of the organics. Three cyclones, located in the oven, were used to separate particles by size (10, 3, and 1 μ m). A filter was used to collect material less than 1 micrometer in diameter. Hot gases were then cooled to about 70°F. The resulting condensate and remaining gases passed through a XAD-2 cartridge to adsorb organic compounds. The condensate then drains into a collection trap and the gases pass through a series of impinger solutions.

The first impinger (30% H_2O_2) traps reducing gases such as SO_2 to prevent a reduction in oxidative capability of the next two impingers. The 0.2 M $(NH_4)_2SO_4/0.02 AgNO_3$ solution in impingers 2 and 3 oxidize volatile trace metals. An additional impinger containing silica gel is used to prevent moisture from damaging the air pump. Twenty to thirty cubic meters of air are sampled during a normal sampling time of five hours.

Although the SASS sampler is one of the most extensively used systems by the EPA to screen for toxic materials, the train does have a few drawbacks. A major problem is that the equipment is fabricated from 316 stainless steel. Therefore, it would not be unusual to find high levels of Cr, Ni, Mo, Mn, and Fe due to leaching (by the acidic condensate) of these elements from the stainless steel parts of the SASS train (e.g.: modules for XAD-2 resin and condensate).

Analyses performed on stack emissions, and associated solid and liquid samples are summarized in the following flow chart (Figure GH-1). Detailed descriptions of the analytical procedures are given later in this appendix. The procedures followed were similar to those specified in the EPA IERL-RTP Level 1 Environmental Assessment Procedures Manual (EPA-600/7-78-201).

4.0 Results and Discussions

The main emphasis of the Level 1 was to screen samples for toxic materials that may be emitted from the coal fired boilers. The analytical results are presented in the following sections.

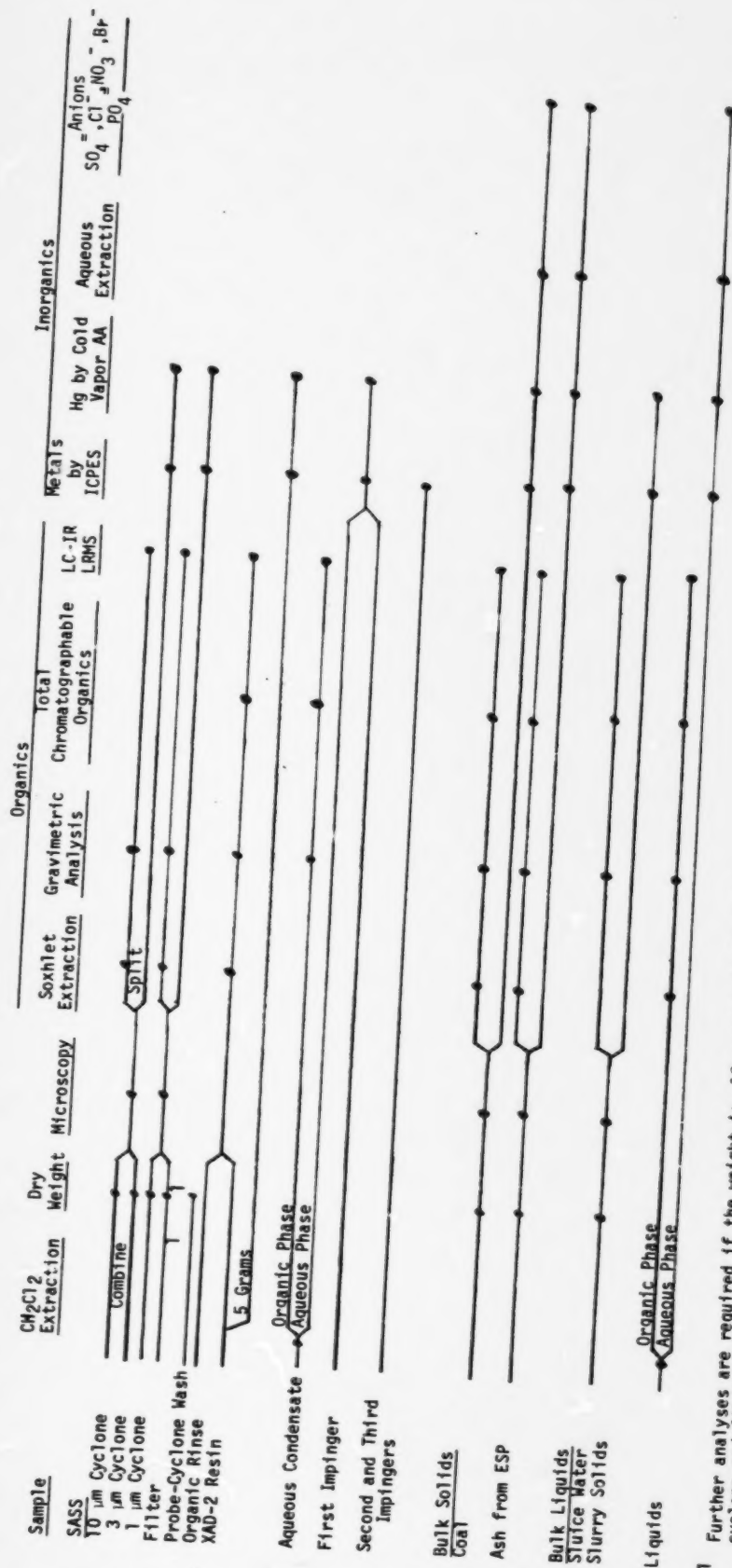
4.1 Particulates

Quantities of particulates collected in the SASS train cyclones and on the final filters are shown in Table GH-3. These data show that most have a diameter greater than 10 μ m. To compare with emissions from other boilers, particulate loadings were calculated on a "per million Btu of heat input" basis. Because of the low residue content in the probe and cyclone rinses, further analyses on these samples were not performed.

Figure GH-1.

Flow Chart

SUMMARY OF ANALYSIS PLAN FOR LEVEL 1 TEST



1 Further analyses are required if the weight is >10 percent of the total cyclone and filter sample weights. Normally the weight is much less than 10 percent.

TABLE GH-3
PARTICULATE MATERIAL COLLECTED IN THE LOUISVILLE SASS TEST

Sample Type	MASS		% Mass	pounds/MBtu ^b
	grams	pounds		
Probe and cyclone rinses	0.658	0.00145	0.26	9.35
10 μ m cyclone	177.300	0.391	69.52	5.55
3 μ m cyclone	66.760	0.147	26.18	2.09
1 μ m cyclone	8.797	0.0194	3.45	0.276
Final Filter ^a				
1	0.294	0.000648	0.12	} 0.0476
2	0.278	0.000613	0.11	
3	0.330	0.000726	0.13	
4	0.320	0.000705	0.13	
5	0.301	0.000664	0.12	
Total	255.038	0.5622	100.02	7.986

- a. No loose particulates.
- b. Mass emission rate per million Btu of heat input (assumes that the volume of gas sampled results from the combustion of 0.0704 MBtu of coal).

4.2 Microscopy

Coal, fly ash, 1 μm , and 10 + 3 μm cyclones particulates were characterized by scanning electron microscopy (SEM) and X-ray energy dispersive techniques. Typical micrographs are shown in Figure GH-2, documenting the morphologies observed. The size ranges and average particle diameters for the particulates (as determined by microscopy) are shown in Table GH-4. The purpose of the SASS 10, 3, and 1 μm cyclones is to trap particulates ≥ 10 , 10-3, and 3-1 μm in diameter, respectively. The 1 micron cyclone catch contained particulates in the expected size range. The 10 and 3 μm cyclones contained some particulates that were < 3 μm in diameter. Louisville fly ash appeared to have a bimodal size distribution with the larger particulates averaging about 20 μm in diameter and the smaller ones averaging about 3-4 μm .

TABLE GH-4		
ACTUAL SIZE RANGE OF CYCLONE CATCHES		
	Size Range (μm)	Average (μm)
1 μm cyclone	0.5 - 3.0	2
10 + 3 μm cyclones	1 - 22	8
Fly ash	0.5 - 40	12

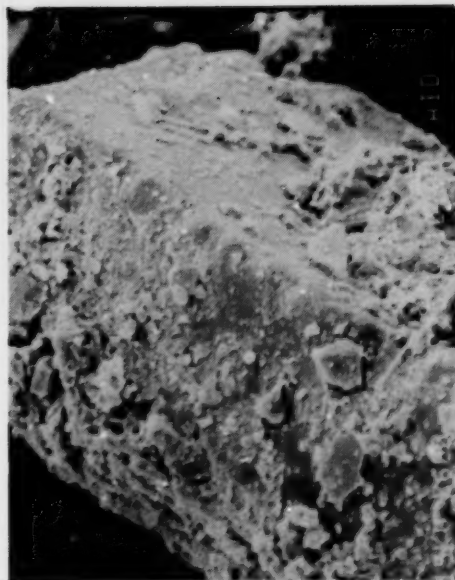
The dominant morphology is spherical. However, the ESP hopper ashes have a greater departure from sphericity than the SASS cyclone particulates and tend to have a rougher surface.

Particles exhibited various degrees of coalescence of mineral grains from the coal. Composition of these particles is dominated by silicates which were probably clays originally. The X-ray energy spectra (Figures GH-3 through GH-6) illustrate typical compositions for each sample. Silicon, aluminum, potassium, and iron are the most abundant elements in the particulates. Calcium, sulfur, and titanium are also present. As expected, sulfur is most predominant in the coal. Also noted in the particulate samples are iron, titanium, and calcium-rich particles. These comprise at most about 10% of the collected samples. Elements detected by X-ray energy dispersive analysis are consistent with those identified by ICPES analysis discussed in the next section.

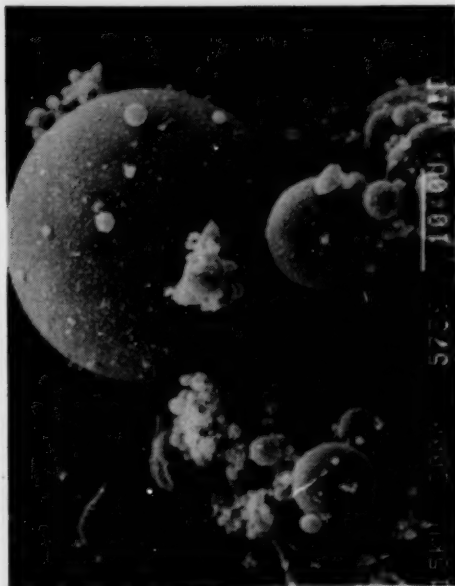
4.3 Metals

Particulate samples, final filters, XAD-2 resin, and impinger solutions were analyzed for metals using ICPES (Inductively Coupled Plasma Emission Spectroscopy). Cold vapor AA was used for the mercury analysis. Each of the four tables of metal data (Tables GH-5 through GH-8) have been divided in two sections with the top half

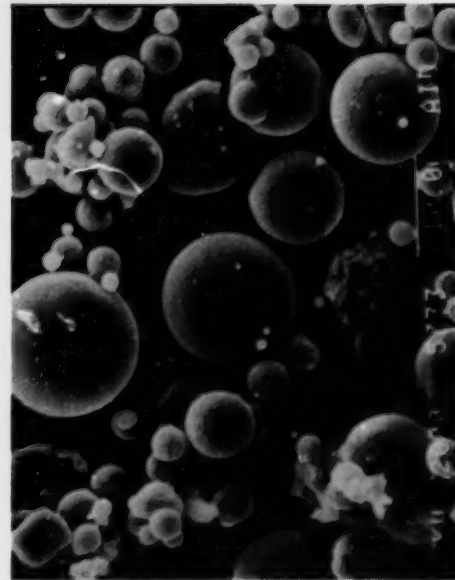
MICROGRAPHS OBTAINED FROM SEM ANALYSIS OF LOUISVILLE SAMPLES



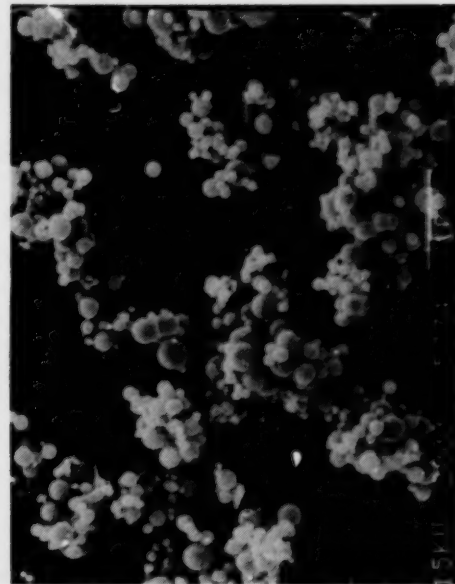
COAL



FLYASH



10 + 3 μ m CYCLONES



1 μ m CYCLONE

FIGURE GH-3
X-RAY ENERGY SPECTRUM
LOUISVILLE COAL

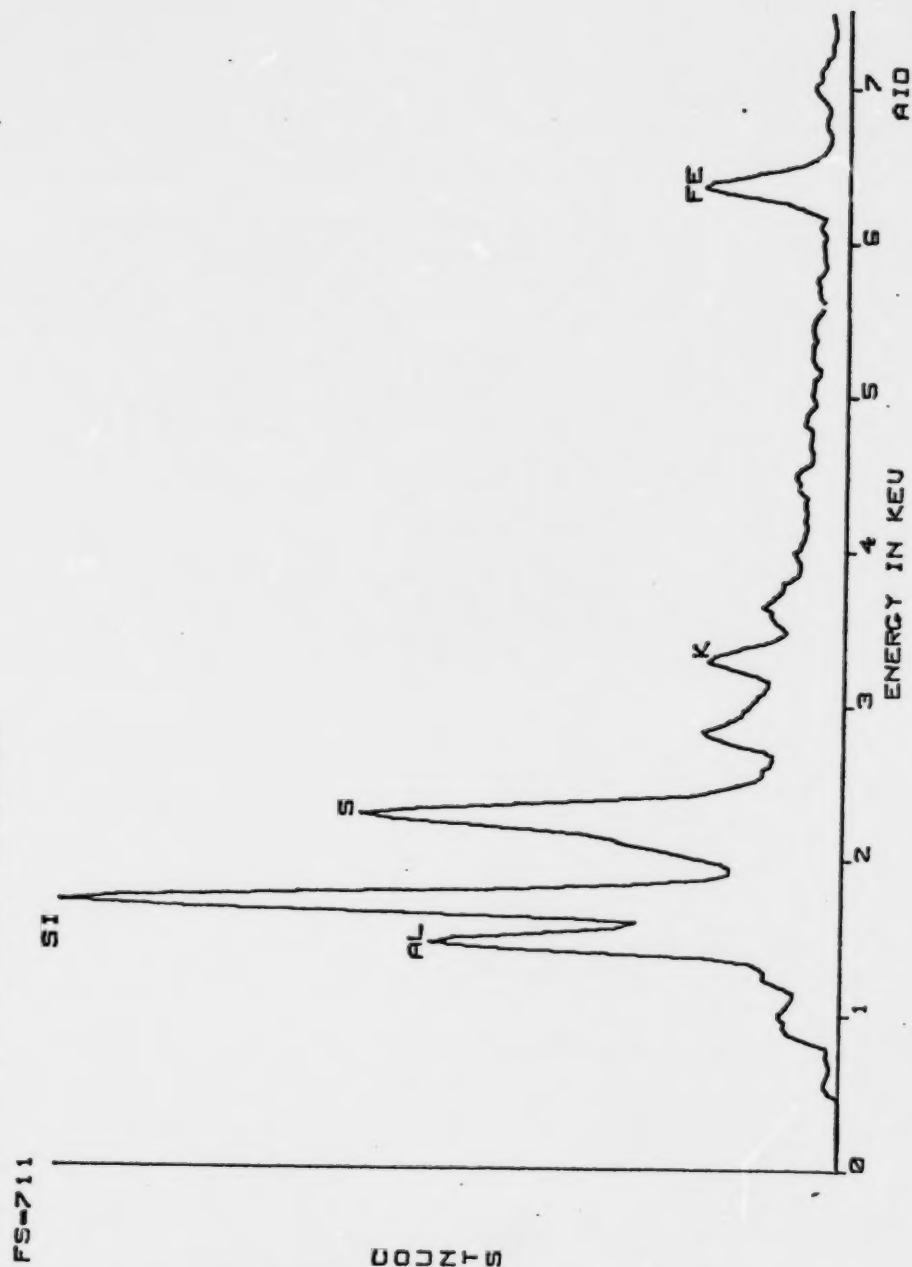


FIGURE GH-4
X-RAY ENERGY SPECTRUM
LOUISVILLE FLYASH

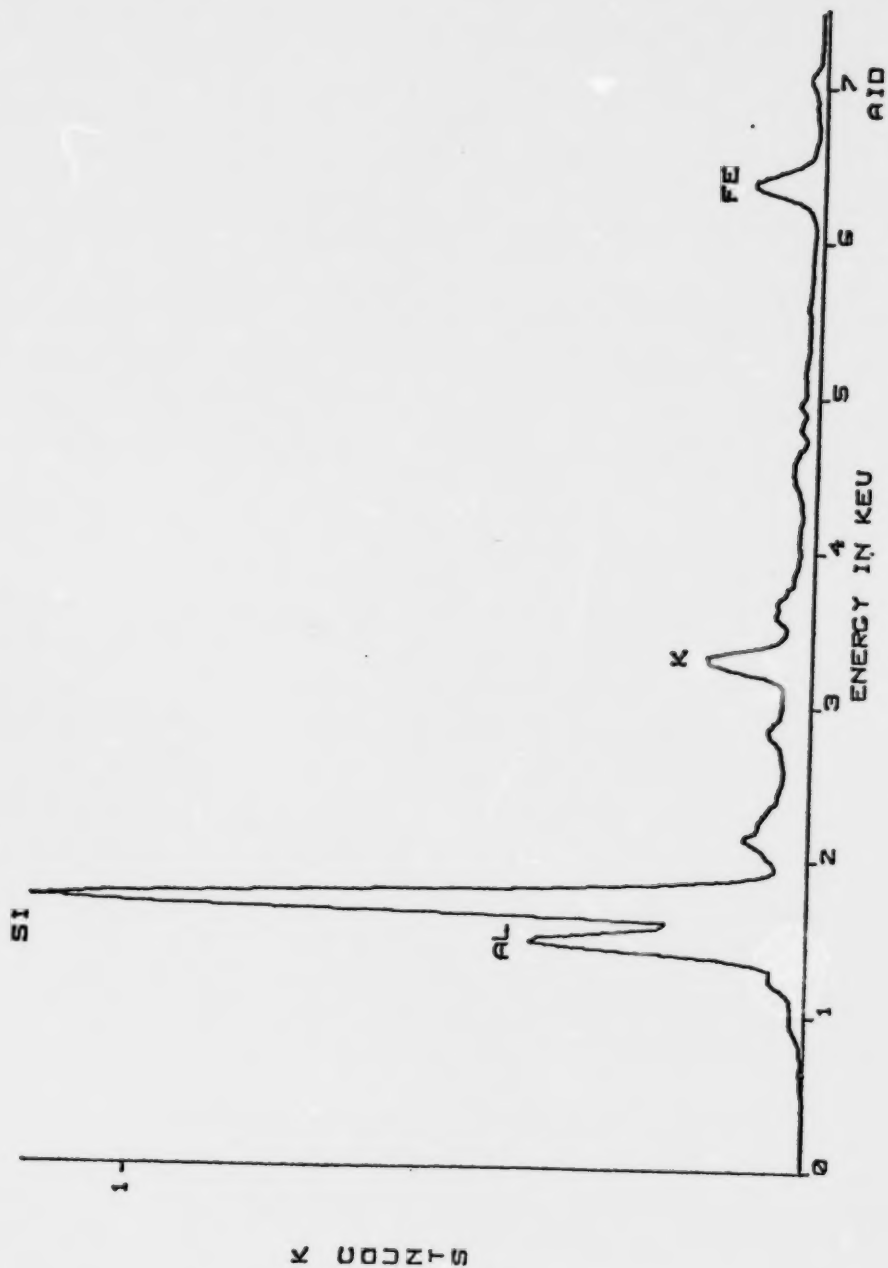


FIGURE GH-5
X-RAY ENERGY SPECTRUM
LOUISVILLE 10 UM + 3 UM CYCLONE

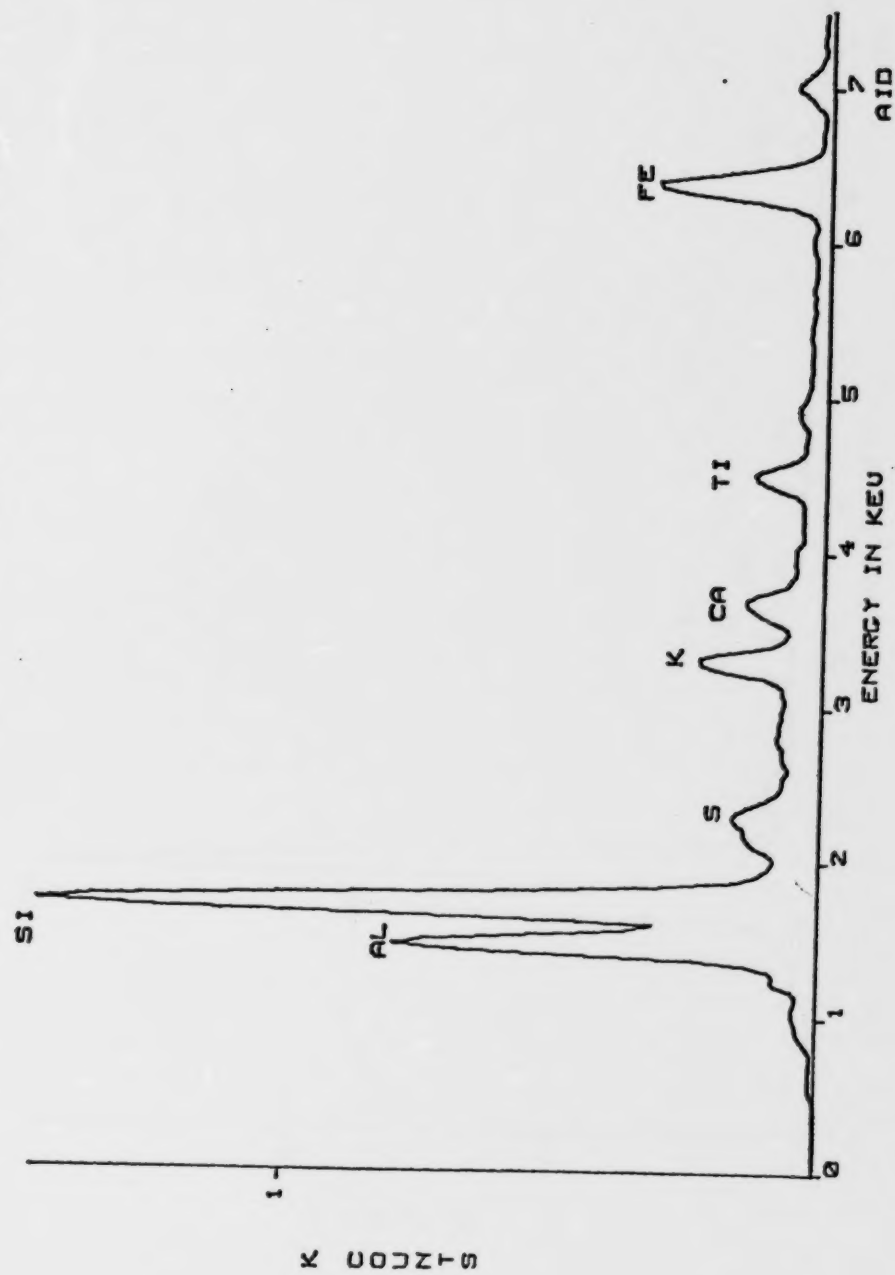


FIGURE GH-6
X-RAY ENERGY SPECTRUM
LOUISVILLE 1 UM CYCLONE

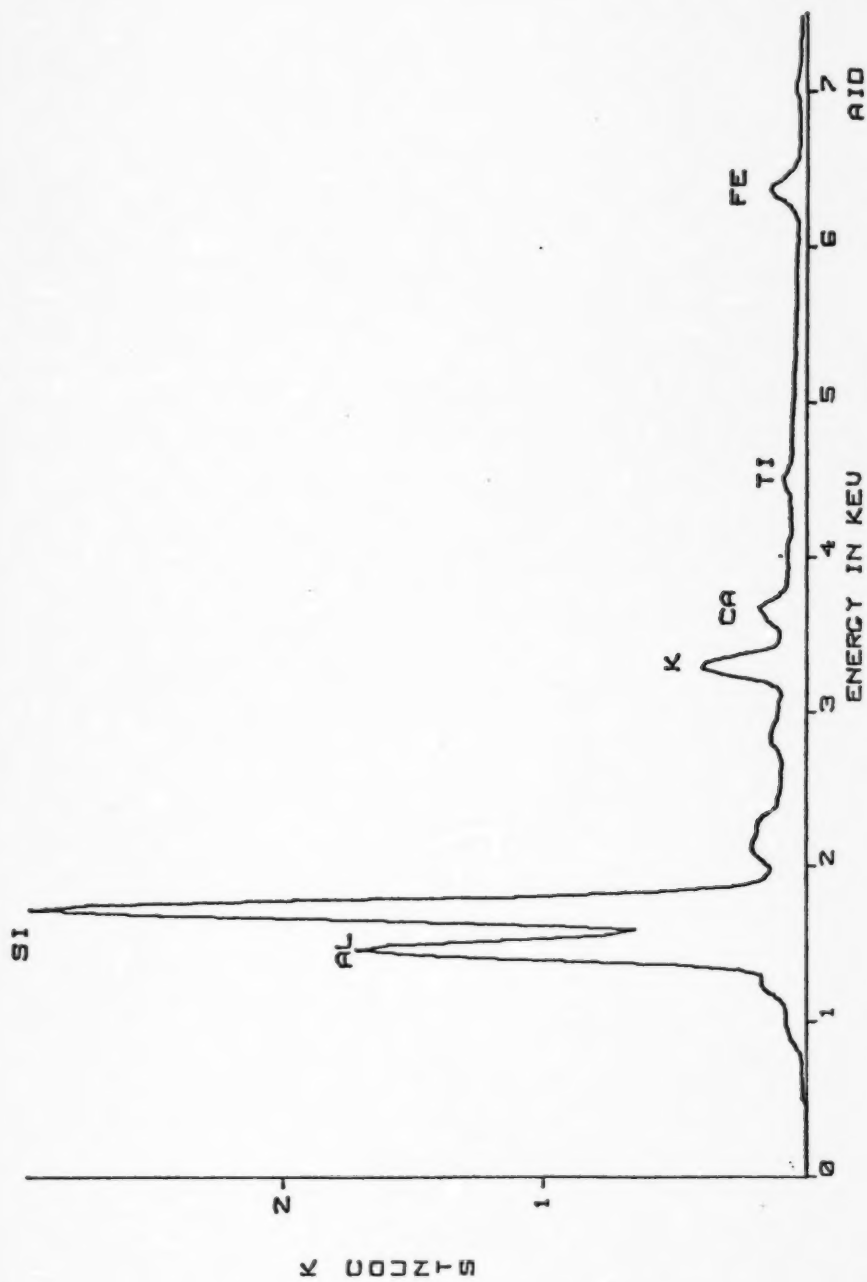


TABLE GH-5

SUMMARY OF METAL EMISSIONS FROM LOUISVILLE SASS TEST

Element	Total mg	pounds/MBtu
Ag	<1.1	34.4×10^{-6}
As	21 ^b	$656. \times 10^{-6}$
Be	(0.85) ^b	(26.6×10^{-6})
Cd	15	$470. \times 10^{-6}$
Cr	58	$816. \times 10^{-6}$
Cu	31	$971. \times 10^{-6}$
Hg	0.090	2.82×10^{-6}
Ni	79	$2471. \times 10^{-6}$
Pb	(14) ^b	$(438. \times 10^{-6})$
Sb	(18) ^b	$(564. \times 10^{-6})^b$
Se	<6.8	$<213. \times 10^{-6}$
Tl	(6.3) ^b	$(197. \times 10^{-6})^b$
Zn	230	$7200. \times 10^{-6}$
Al	25000	0.783
Ba	140	$4380. \times 10^{-6}$
Ca	7500	0.235
Co	(0.77)	(241)
Fe	28000	0.877
K	6200	0.194
Li	20	$626 \times \times 10^{-6}$
Mg	1400	0.0438
Mn	86	$2690. \times 10^{-6}$
Mo	30 ^b	$(939 \times 10^{-6})^b$
Na	2100	0.0658
P	270	$8455. \times 10^{-6}$
Si	52000	1.628
Sh	(0.34) ^b	$(10.6 \times 10^{-6})^b$
Sr	52	$1630. \times 10^{-6}$
Ti	1300	0.0407
V	110	$3130. \times 10^{-6}$

- a. Data less reliable due to significant spectral or background interferences.
- b. Data unreliable due to strong interferences or weak signals.
- () Means that the value is less than 3 times the ICPEs detection limit or the blank value. These results may not be significant since they are more easily affected by background fluctuations.
- < Means that the printed value represents the lower limit of detection for the element in that particular sample.

Table GH-6. METAL DATA FROM LOUISVILLE LEVEL 1 TEST
(RESULTS REPORTED IN $\mu\text{g/g}$)

Element	10 + 3 μm Cyclones	1 μm Cyclones	Coal	Flyash	Make Up Feed Water	Sluice Water
Ag	<4.2	<5.0	<6	(12)b	<.0025	<0.0029
As	67b	350a	<25	90b	(0.011)	(0.018)
Be	(2.7)b	20b	(3.2)b	8.2b	<0.0006	<0.0007
Cd	57	110	<11	(18)	<0.0047	<0.0053
Cr	140	260	<1.8	110	0.024	<0.0008
Cu	110	190	9.7	96	<0.0002	<0.0002
Hg	0.058	0.0021	0.0020	0.025	<0.0001	<0.0001
Ni	240	330	<15	200	<0.0064	<0.0073
Pb	(47)b	190	<19	<21	<0.0078	<0.012
Sb	(69)b	(72)b	(58)b	(67)b	<0.015	<0.017
Se	<17	280b	<25	<21	<0.010	<0.012
Tl	(22)b	87b	<11	45b	<0.0048	<0.0055
Zn	820	3100	62	780	0.061	0.11
Al	98000	120000	14000	92000	0.021	1.6
Ba	540	800	58	570	0.075	0.11
Ca	30000	26000	5400	30000	72	91
Co	<3.4	40a	(9.2)	<4	<0.002	(0.0035)
Fe	110000	79000	11000	120000	<0.0011	2.4
K	24000	26000	3200	23000	4.2	6.6
Li	79	100	6.8	75	0.0065	0.03
Mg	5500	7900	770	5300	14	16
Mn	330	430	45	320	<0.0001	0.025
Mo	100b	320b	<9.8	96b	(0.0072)	0.052
Na	4100	4600	800	3500	25	28
P	900	4200	<54	1100	(0.051)	0.13
Si	210000	120000	66000	100000	0.73	0.54
Sn	<13	(38)b	<19	<16	<0.0078	<0.009
Sr	200	300	20	190	0.30	0.29
Ti	4800	6200	330	4400	<0.0005	0.13
V	410	1200	<11b	480	<0.0045	0.069

- a Data less reliable due to significant spectral or background interferences.
b Data unreliable due to strong interferences or weak signals.
() Means that the value is less than 3 times the ICPEs detection limit or the blank value. These results may not be significant since they are more easily affected by background fluctuations.
< Means that the printed value represents the lower limit of detection for the element in that particular sample.

TABLE GH-7

METAL DATA ON STACK EMISSIONS FROM LOUISVILLE SASS TEST
(Results Reported In Total mg Collected)

Element	10 & 3 μ m Cyclones	1 μ m Cyclone	Final Filters	XAD-2 Resin	Impinger 1 + Condensate	Imp 2 + 3
Ag	<1.0	<0.044	(0.0053) ^b	<0.0086	<0.032	
As	16 ^b	3.1 ^a	2.1	<0.036	<0.026	<0.0035
Be	(0.67) ^b	0.17 ^b	0.013 ^a	<0.0020	<0.0038	
Cd	14	0.99	0.042	<0.016	<0.035	
Cr	34	2.3	0.12	0.90	21	
Cu	27	1.7	<0.14	(0.26)	1.8	
Hg	0.014	0.00002			0.016	0.06 ^d
Ni	58	2.9	0.06	<0.56	18	
Pb	(12) ^b	1.6	0.054	<0.14	(0.031) ^b	
Sb	(17) ^b	(0.63) ^b	<0.043 ^a	<0.052	0.054 ^b	<0.0052
Se	<4.2	2.5 ^b	<0.0084	<0.036	(0.025) ^b	
Tl	(5.3) ^b	0.76 ^b	<0.039	<0.017	0.20 ^b	
Zn	200	27	0.47	<1.3	2.0	
Al	24000	1040	28	(0.36)	2.8	
Ba	130	7	0.35	<0.031	0.041	
Ca	7200	230	47	<1.1	23	
Co	<0.82	0.35 ^a	(0.0038)	<0.0069	0.42	
Fe	27000	700	9.7	3.8	120	
K	6000	230	2.6	<0.41	0.47	
Li	19	0.92	0.0034	<0.001	0.0078	
Mg	1300	70	<0.46	<1.2	3.9	
Mn	79	3.8	0.054	0.076	2.8	
Mo	25 ^b	2.8 ^b	0.56	<0.15	2.1	
Na	1000	41	100	<1.9	1000	
P	220	37	9.9	<0.40	0.09 ^b	
Si	51000	1100	1.1	<0.042	0.07 ^a	
Sn	<3.2	(0.34) ^b	<0.0064	<0.027	<0.0092	
Sr	49	2.6	0.16	0.13	0.023	
Ti	1200	54	0.6	<0.23	0.11	
V	99	10	2.1	<0.015	0.083	

- a Data less reliable due to significant spectral or background interferences.
b Data unreliable due to strong interferences or weak signals.
() Means that the value is less than 3 times the ICPES detection limit or the blank value. These results may not be significant since they are more easily affected by background fluctuations.
< Means that the printed value represents the lower limit of detection for the element in that particular sample.

TABLE GH-8

METAL DATA ON BLANKS FROM LOUISVILLE SASS TEST
(Results Reported In Total mg Per Test)

Element	Filter	XAD-2	Imp 1	Imp 2 & 3
Ag	<0.0020	<0.012	0.085	
As	<0.0084	<0.047	<0.0043	(0.010)
Be	<0.00048	<0.0027	<0.00025	
Cd	<0.0038	<0.021	<0.0020	
Cr	0.0050	0.041	0.0030	
Cu	0.072	0.30	0.0053	
Hg			<0.00004	<0.00003
Ni	<0.0052	5.4	<0.0027	
Pb	<0.0084	0.22	(0.0052)	
Sb	<0.012	<0.070	<0.0064	(0.0052) ^a
Se	<0.0084	<0.047	<0.0043	
Tl	<0.0039	<0.022	(0.0047)	
Zn	0.033	1.3	0.044	
Al	0.27	0.39	0.028	
Ba	0.0031	0.031	0.0021	
Ca	1.1	1.1	0.23	
Co	<0.0016	<0.0093	<0.00087	
Fe	0.060	1.4	0.040	
K	<0.008	0.41	<0.0041	
Li	(0.0002)	(0.0011)	<0.000083	
Mg	0.089	1.2	0.22	
Mn	<0.00012	0.019	0.00025	
Mo	(0.0058)	0.15	<0.0017	
Na	0.15	2.3	0.25	
P	<0.018	0.40	(0.018)	
Si	0.085	0.26	0.036	
Sn	(0.018)	<0.036	<0.0033	
Sr	0.0016	0.0072	0.00017	
Ti	0.014	0.23	0.014	
V	<0.0036	<0.021	<0.0019	

^a Data less reliable due to significant spectral or background interferences.

^b Data unreliable due to strong interferences or weak signals.

() Means that the value is less than 3 times the ICPEs detection limit or the blank value. These results may not be significant since they are more easily affected by background fluctuations.

< Means that the printed value represents the lower limit of detection for the element in that particular sample.

showing the elements designated on EPA's priority pollutants list for toxin in wastewater. Table GH-5 summarizes the total metal emissions collected by the SASS. Tables GH-6 and GH-7 show the distribution of the metals among the Level 1 samples and are followed by Table GH-8 which shows metals in the control "blanks". The tables show that most (largest mass of) metals are present in the particulates, and, as expected, mercury was found at higher levels in the impinger samples.

The second and third impingers are used to entrap volatile elements, namely As, Hg, and Sb. This is accomplished by oxidative dissolution of these elements using a solution of ammonium persulfate and silver nitrate. The data show that except for mercury, other volatile metals were at or near their detection limits (<100 mg/SASS test).

Because the SASS train is fabricated from 316 stainless steel high levels of Fe, Ni, Mn, Mo, and Cr are not unusual. The acid content of the gases would determine the amount of metals leached from the sample walls.

Metal data for stack emissions are consistent with material found in the fly ash. Metals appear to be more concentrated on the 1 μ m particles and fly ash samples than on the 10 + 3 μ m size particles and coal samples. This is probably due to unburned carbon on the larger particles. Total stack emissions show that most (greatest mass of) metals are contained in the 10 + 3 μ m particles. The associated water samples contain very low metal levels.

4.4 Anions

Bulk coal and fly ash samples were water-extracted and analyzed for anions using ion chromatography according to Figure GH-7 showing the analysis scheme for bulk solids and liquids. (Figure GH-8 shows the analysis scheme for the flue gas and entrained particles.) The results (Table GH-9) show that only low concentrations of extracted sulfate were measured. Bulk water samples collected during the SASS train tests were also analyzed. Chloride and sulfate were measured in the liquid samples.

TABLE GH-9					
ANION ANALYSIS OF SOLIDS AND LIQUID SAMPLES					
Sample	Cl ⁻	PO ₄ ³⁻	Br ⁻	NO ₃ ⁻	SO ₄ ²⁻
Solids (wt % H ₂ O) extracted)					
Louisville Coal	<0.05	<0.1	<0.1	<0.1	1.2
Louisville Fly ash	<0.05	<0.1	<0.1	<0.1	2.0
Liquids (g/mL)					
Louisville Make-Up Water	31	<10	<10	<10	100
Louisville Sluice Water	31	<10	<10	<10	150

FIGURE GH-7

ANALYSIS SCHEME FOR BULK SOLIDS AND LIQUIDS

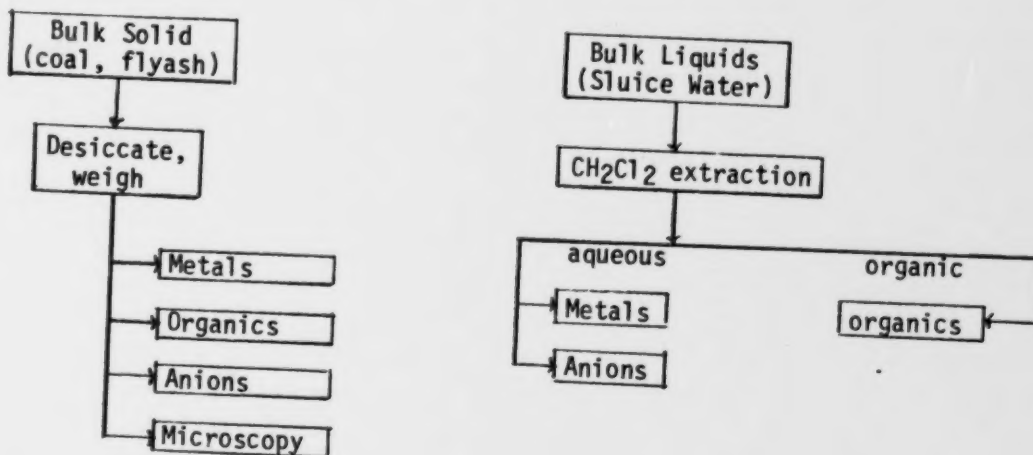
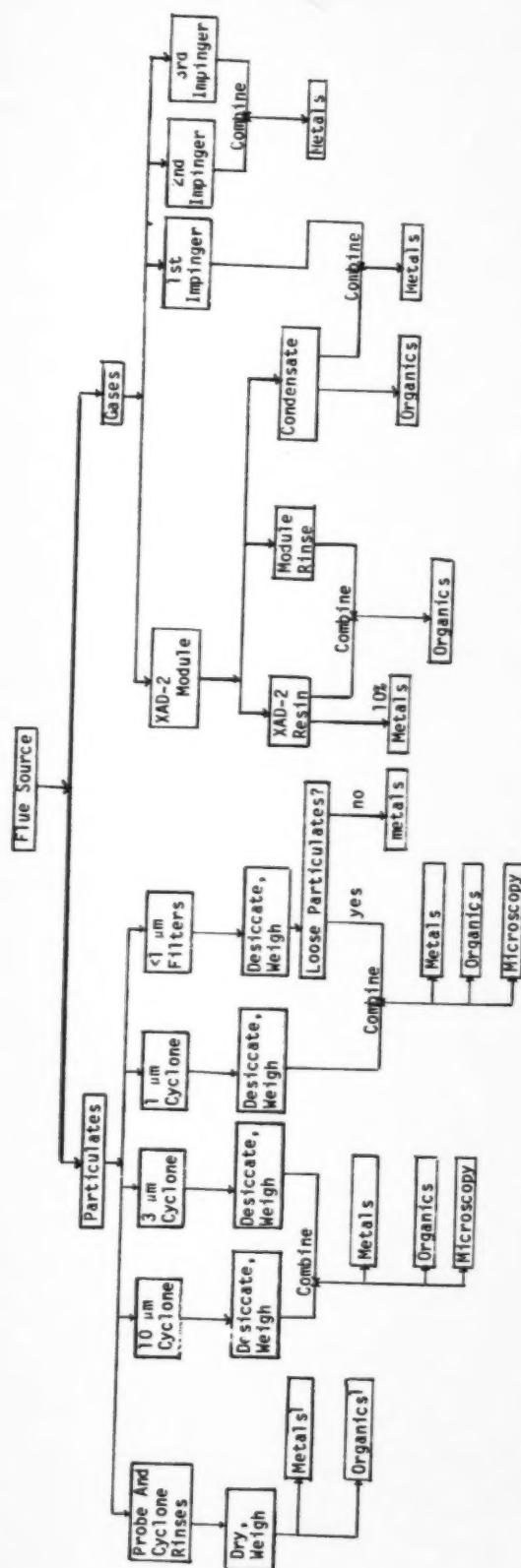


FIGURE GH-8
Analysis Scheme For Flue Gases And Particulates



1 Analyzed when >10% of the particulate catch.

4.5 Organics

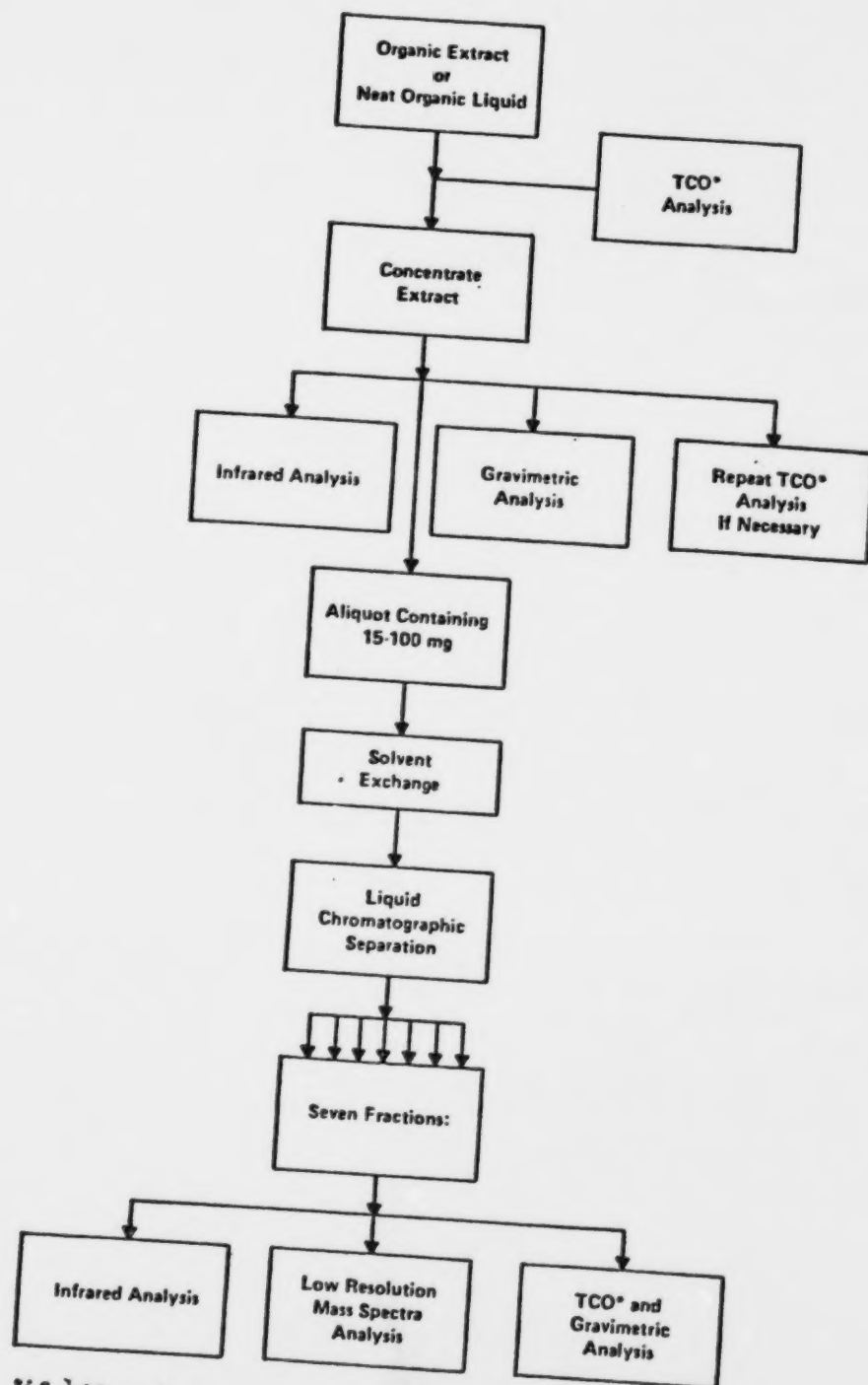
The organics extracted from the particulates and XAD-2 resin were measured by gravimetric and gas chromatographic techniques. When there were sufficient quantities, a silica gel separation scheme was used to isolate compound classes. Infrared and mass spectrometry were used to identify classes and specific compounds. The flow charts (Figures GH-8 and GH-9), highlight the analytical procedures.

Results of gravimetric and total chromatographable organics (TCO) data on the concentrated extracts are shown in Table GH-10. Data presented in these tables are based on the total SASS sample, not just the fraction used in the analysis. The EPA Level 1 protocol specifies that if the sum of the total extractable organics is greater than 15 mg, the extract should be further characterized using a silica gel separation scheme to isolate compound classes. Only the SASS XAD-2 resin extract required further separations. (The blank XAD-2 contained only 6.4 mg of total extractable organics and was therefore not analyzed further.) Because the particulates were held at 400°F it was not unexpected that most organics condensed onto the XAD-2 adsorbent that was chilled to less than 70°F. Silicic acid column chromatography was also performed on the coal extracts.

Quantities of organics isolated after silica gel separation of the XAD-2 and coal extracts are shown in Table GH-11. The table shows that most compounds in the XAD-2 extract were isolated in fractions 6 and 7 for, and that organic distributions in the coal extracts were evenly spread over the seven silica gel fractions.

The Fourier Transform Infrared (FTIR) method was used to analyze for major functional groups. Based on the EPA protocol, a listing of the major peaks and possible assignments are given in the Tables GH-12 through GH-20 (one table for the uncut sample, and one for each of the seven cuts, and one for the blank). For each spectrum, intensities are reported relative to the strongest peak in the spectrum (S = strong, 70-100%; M = medium, 30-70%; W = weak, < 30%). Hence comparisons between peaks in different spectra cannot be made. Subsequent analysis revealed that major compounds in the XAD-2 fraction 6 were alkyl esters. However, similar compounds were observed in the unseparated methylene chloride extract of a blank XAD-2 sample.

Because most compounds were in cuts 6 and 7, these fractions were analyzed by GC/MS. Also, two major components were found in the organics extracted from a the blank XAD-2. They were identified as di-octyl esters of adipic and phthalic acids as indicated in the mass spectra plots (Figures GH-10 and GH-11). Phthalate and adipate contaminants in the XAD-2 extracts are consistent with the FTIR data. Therefore, these peaks in the IR tables that follow should be discounted partially due to contaminants in the blank. The reader should note that the concentration of organics in the blank was only about 6/125 (from Table GH-10) or 5% of the total measured amount.



*if ≥ 40 mg/l

FIGURE GH-9. Organic analysis methodology.

TABLE GH-10

MASS OF EXTRACTABLE ORGANICS FROM LOUISVILLE SASS TEST

Sample Type	Gravimetric	TCO	Total (mg/test)
10 + 3 μ m cyclones	4.1	—	4.1
1 μ m cyclone	<0.5	—	<0.5
XAD-2 Resin (uncorrected)	120.6	4.5	125.1
Blank XAD-2	6.2	0.2	6.4
XAD-2 (corrected for blank)	114.4	4.3	118.7
Condensate	<0.2	<0.1	<0.2
Coal (mg/g) ^a	15.86	1.69	17.55
Fly ash (mg/g) ^b	0.07	<0.01	0.07
Water (mg/L) ^c	0.19	<0.01	0.19

^a amount extracted--73.45 g
^b amount extracted--75.52 g
^c amount extracted--5.90 L

TABLE GH-11

MASS OF EXTRACTABLE ORGANICS SEPARATED
ON SILICA GEL FOR LOUISVILLE SASS TEST

Silica Gel Fraction	XAD-2 (mg/SASS Test)			Coal (mg/g) ^b		
	Grav.	TCO	Total	Grav.	TCO	Total
1	4.0	<0.1	4.0	3.16	1.13	4.29
2	1.1	<0.1	1.1	0.32	0.09	0.41
3	1.1	<0.1	1.1	3.50	0.24	3.74
4	4.5	<0.1	4.5	2.36	<0.01	2.36
5	6.9	<0.1	7.0	1.96	<0.01	1.96
6	51.1	0.9	52.0	5.98	0.01	5.99
7	19.9	0.3	20.2	0.20	<0.01	0.20
TOTAL	88.6	1.3	89.9	17.48	1.47	18.95

^a Portion used for the LC separation was 87.0 mg of the 125.1 mg sample (Table GH-10). Results are computed for the total sample.

^b Portion used for LC separation was 14.92 mg of the 17.55 mg sample (Table GH-10). Results are computed for the total sample.

TABLE GH-12

LOUISVILLE XAD-2 EXTRACT BEFORE COLUMN

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
2955	M	aliphatic CH
2918	S	aliphatic CH
2848	M	aliphatic CH
1735	M	ester C=O
1695	M	acid C=O
1462	M	aliphatic CH
1378	W	aliphatic CH methyl
1300-1100	W	broad multiplet; various C-O
720	W	aliphatic CH ₂

Unassigned weak bands
1410, 938

Other Remarks:

Quality spectra could not be obtained with amount of material available. Baseline variation due to scattering makes observation of broad acid OH impossible.

TABLE GH-13

LOUISVILLE SASS XAD-2 COLUMN CUT NO. 1

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
2957	M	aliphatic CH
2920	S	aliphatic CH
2852	M	aliphatic CH
1462	W	aliphatic CH
1378	W	aliphatic (methyl)
720	W	aliphatic CH ₂ long chain

Other Remarks:

Very weak 1740 and 1240 bands present due to minor ester component.

TABLE GH-14

LOUISVILLE SASS XAD-2 COLUMN CUT NO. 2

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
3095, 3060, 3022	W	aromatic CH
2952	M	aliphatic CH
2919	S	aliphatic CH
2850	M	aliphatic CH
1738	W	ester C=O
1600	W	aromatic ring stretch
1493	W	aromatic ring stretch
1461	W	aliphatic CH
1378	W	aliphatic CH (methyl)
1242	W	ester C-O-C
1120, 1074, 1030	W	aromatic CH in plane bend
758	W	aromatic CH out of plane bend
720	W	aliphatic CH ₂ long chain
698	W	aromatic C-C bend

Unassigned weak bands
1287 shoulder

Other Remarks:

- Ester is probably acetate of saturate alcohol.
- Aromatic present is a monoalkyl benzene.

TABLE GH-15

LOUISVILLE XAD-2 COLUMN CUT NO. 3

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
3020	W	aromatic CH
2952	M	aliphatic CH
2919	S	aliphatic CH
2850	M	aliphatic CH
1738	W	ester C=O
1460	W	aliphatic C-H
1380	W	aliphatic CH (methyl)
1242	W	ester C-O-C
750	W	aromatic CH bend
698	W	aromatic ring bend

Other Remarks:

- Spectrum quality poor due to insufficient sample.
- Cut 3 is quite similar to cut 2, containing acetate ester and mono-alkyl benzene.

TABLE GH-16

LOUISVILLE SASS XAD-2 COLUMN CUT NO. 4

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
2950	M	aliphatic CH
2920	S	aliphatic CH
2852	M	aliphatic CH
1742	M	ester C=O
1464	W	aliphatic CH
1437	W	CH ₃ of methyl ester
1378	W	aliphatic CH
1365	W	CH ₃ of methyl ester
1245, 1197, 1171, 1115	W	ester C-O
720	W	aliphatic CH ₂ long chain

Unassigned weak bands
1512, 1365, 1018, 878

Other Remarks:

Cut 4 appears to be a mixture of aliphatic esters, principally methyl esters of long chain acids.

TABLE GH-17

LOUISVILLE SASS XAD-2 COLUMN CUT NO. 5

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
2950	M	aliphatic CH
2920	S	aliphatic CH
2850	M	aliphatic CH
1742	M	ester C=O
1465	W	aliphatic CH
1437	W	CH ₃ of methyl ester
1378	W	aliphatic CH (methyl)
1365	W	CH ₃ of methyl ester
1247, 1198, 1172, 1116	W	ester C-O
720	W	aliphatic CH ₂ long chain

Unassigned weak bands
1512, 1020, 880

Other Remarks:

Methyl esters of long chain acids are principal component.
Cut 5 is very similar to Cut 4.

TABLE CH-18

LOUISVILLE SASS XAD-2 COLUMN CUT NO. 6

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
3600-2300	W	broad, OH
3060, 3020	W	aromatic CH
2954, 2924, 2837	M	aliphatic CH
1736	S	ester C=O
1602	M	aromatic ring stretch
1450	M	aliphatic CH
1438	*	CH ₃ of methyl ester
1378	*	aliphatic CH (methyl)
1367	*	CH ₃ of methyl ester
1265, 1210, 1180, 1140, 1078, 1010	M	various ester vibrations
760	W	aromatic CH bend
702	W	aromatic ring bend

*Weak bands on medium background.

Unassigned weak bands

1560 (sh), 1515, 1420, 890, 865, 835

TABLE GH-19

LOUISVILLE SASS XAD-2 COLUMN CUT NO. 7

Major Peaks and Assignments

<u>cm⁻¹</u>	<u>Intensity</u>	<u>Assignment</u>
3600-2300	W	broad, OH
2950	M	aliphatic CH
2922	S	aliphatic CH
2852	M	aliphatic CH
1730	S	ester C=O
1710-1770	S	shoulder, acid C=O
1605	W	aromatic ring stretch
1460	M	aliphatic CH
1380	M	aliphatic CH (methyl)
1245, 1195, 1180, 1140, 1075	M	various ester (acid) vibrations
760	W	aromatic CH bend
703	W	aromatic ring bend

Other Remarks:

Spectrum quality was poor due to insufficient material. Weak peaks could not accurately be distinguished from spectral noise.

TABLE GH-20

XAD-2 BLANK

Major Peaks and Assignments

<u>cm⁻¹(1)</u>	<u>Intensity</u>	<u>Assignment</u>
2958, 2920	S	aliphatic C-H
2864, 2858	M	aliphatic C-H
1732	S	ester C=O
1600	W	aromatic
1452	M	aliphatic C-H
1378	W	aliphatic C-H (methyl)
1300-950	S	broad multiplet; various C-O
795, 702	W	aromatic

Unassigned weak bands
1585, 1508, 1485, 905, 830

Other Remarks:

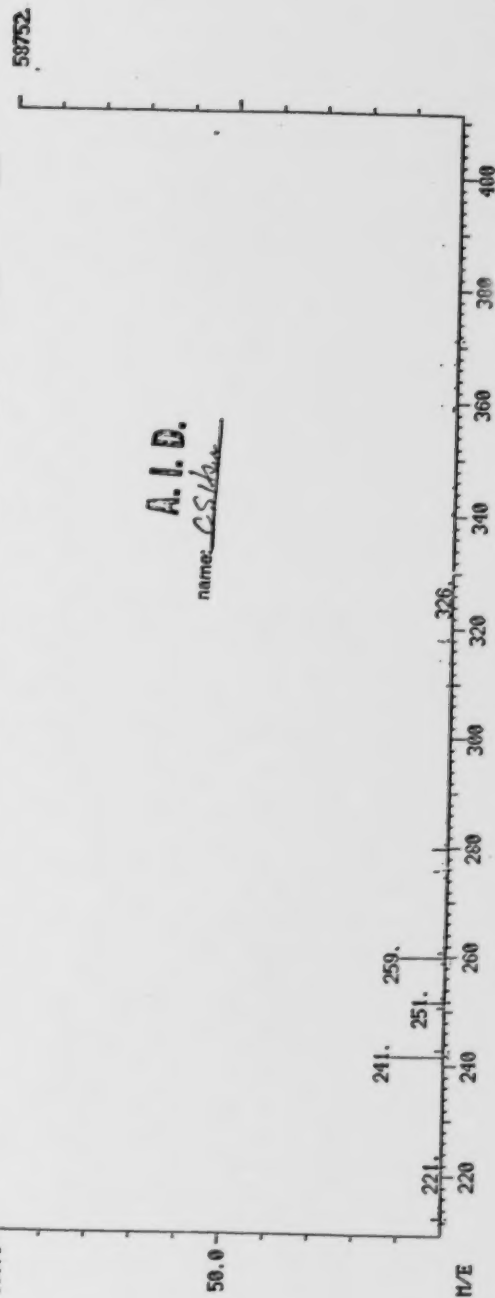
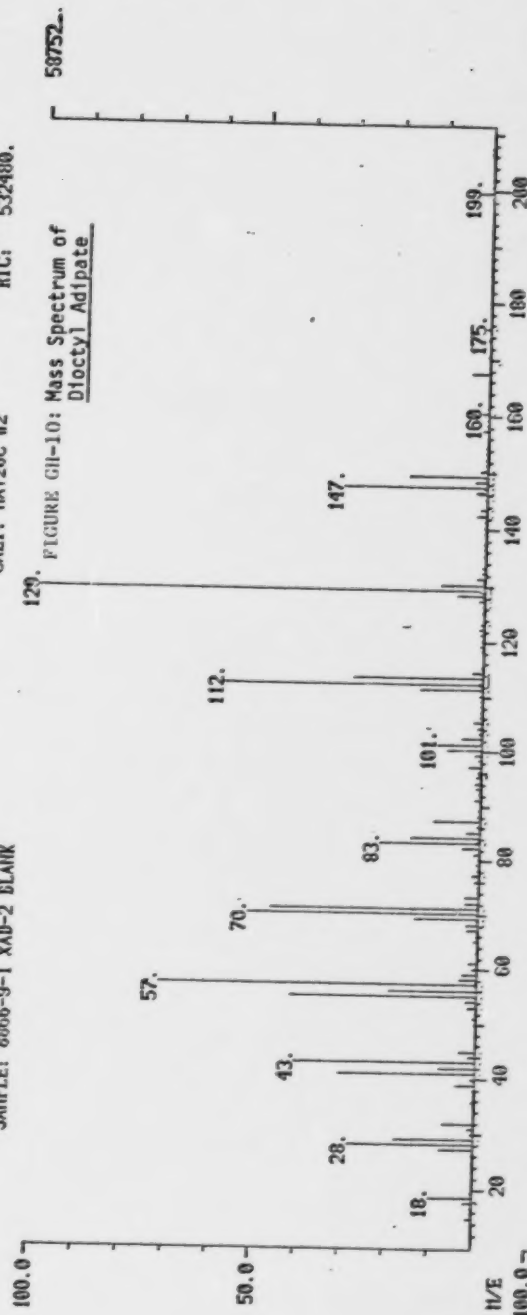
Material appears to be highly oxygenated, possibly polyether and/or polyester.

(1) Frequencies are to ± 1 cm⁻¹ in the 2000-450 cm⁻¹ region and to ± 3 cm⁻¹ between 3800 and 2000 cm⁻¹.

MASS SPECTRUM
05/20/81 13:54:00 + 4:29
SAMPLE: 8066-9-1 XAD-2 BLANK

DATA: 810544 #69
CALL: HAY20C #2

BASE M/E: 129
RIC: 532480.



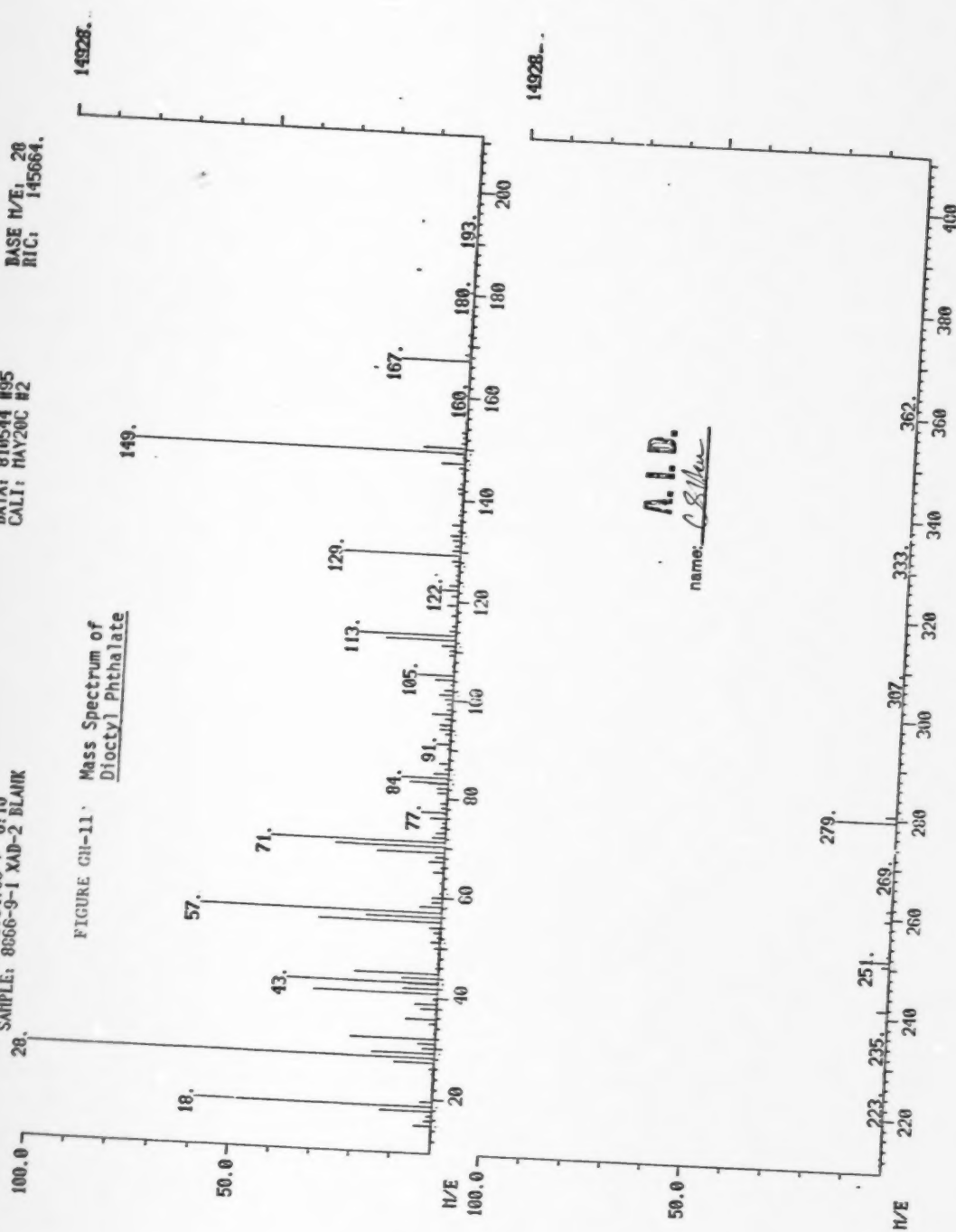
A.I.D.

name: C.S. Kane

MASS SPECTRUM
05/20/81 13:54:00 + 6:10
SAMPLE: 8666-9-1 XAD-2 BLANK

DATA: 810544 H95
CALI: HAY20C H2
BASE N/E: 20
RIC: 145664.

FIGURE GH-11. Mass Spectrum of
Diethyl Phthalate



A.I.D.
name: C.S. Hsu

The reconstructed ion chromatogram of cut 6 (Figure GH-12) from the XAD-2 fractions shows that the most abundant compound in cut 6 is methyl hexadecanoate. Some glycol ethers may also be present in Louisville cut 6; and, cut 7 (Figure GH-13) contains a significant amount of dimethyl sulfate (see Figures GH-14 and GH-15). Also, many silicon-containing materials and methyl esters of aliphatic acids were detected in this fraction, some of which may have been due to contaminants in the blank (See previous paragraph.) The presence of dimethyl sulfate (B.P. 188.5°C) is of concern because it is a suspected human carcinogen by the American Conference of Governmental Industrial Hygienists. Because dimethyl sulfate decomposes above 188°C and is easily hydrolyzed, one would not expect this compound to survive in the SASS cyclones (204°C) or on the aqueous soaked XAD-2 resin. Although some dimethyl sulfate may survive, it is more likely that acidic sulfates extracted by methylene chloride or impurities in the chromatographic column used to separate organic classes reacted with methanol, an eluting solvent, to form dimethyl sulfate. Silica gel and sodium sulfate are used in the EPA Level 1 separation scheme. A recent study⁽¹⁾ has shown that methanol contributes to artifact formation of dimethyl sulfate in stack emissions. This study also reports that dimethyl sulfate is present on particulate emissions from coal and oil fired power plants. These particulates were collected below the decomposition temperature of dimethyl sulfate. Since the SASS is not suitable to sample for dimethyl sulfate it is unknown if this compound was emitted from the boilers tested under this program.

Degradation products of the XAD-2 resin have been reported in stack emissions containing nitrous oxides in the 460-810 PPM range.⁽²⁾ Mainly aromatic acids, aldehydes, and esters were reported. Considering that NO_x concentrations were about 400 ppm, it is possible that some of the compounds detected were degradation products of the XAD-2 resin.

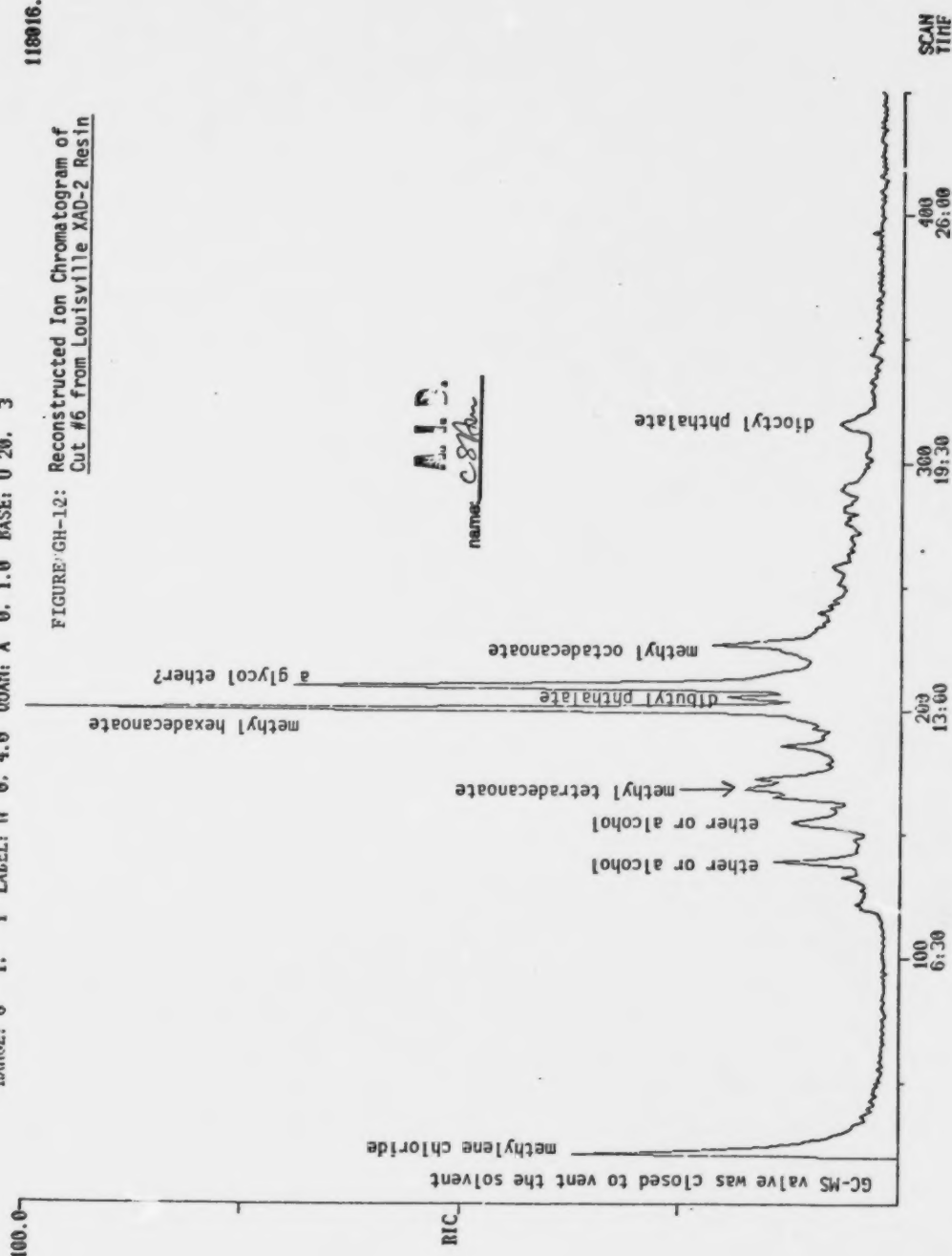
Silica gel fractions of the coal extracts were analyzed by FTIR. The spectra were too complex to be analyzed by the EPA protocol. Instead of listing peaks and assignments, a brief description of major components in each fraction, as indicated by the FTIR, follows. In general, the coal extracts are highly aromatic and highly oxygenated (phenols, carboxylic acids). No further analyses were performed on these samples.

5.0 References

1. D. J. Eatough, M. C. Lee, D. W. Later, B. E. Richter, N. L. Eatough, and L. D. Hansen, Environ. Sci. Technol., 15, 1502, (1981).
2. R. L. Hanson, C. R. Clark, R. L. Carpenter, C. H. Hobbs, Environ. Sci. Technol., Vol. 15, No. 15, pg. 701, (1981).

RIC
 10/09/81 10:02:00
 SAMPLE: 8866-9-12 CUT#6 XAD-2
 RANGE: 6 1. 1 LABEL: N 0, 4.0 QUAN: A 0, 1.0 BASE: U 20, 3
 DATA: 811030 #1
 CALL: OCT9 W2
 SCANS 1 TO 450
 118016.

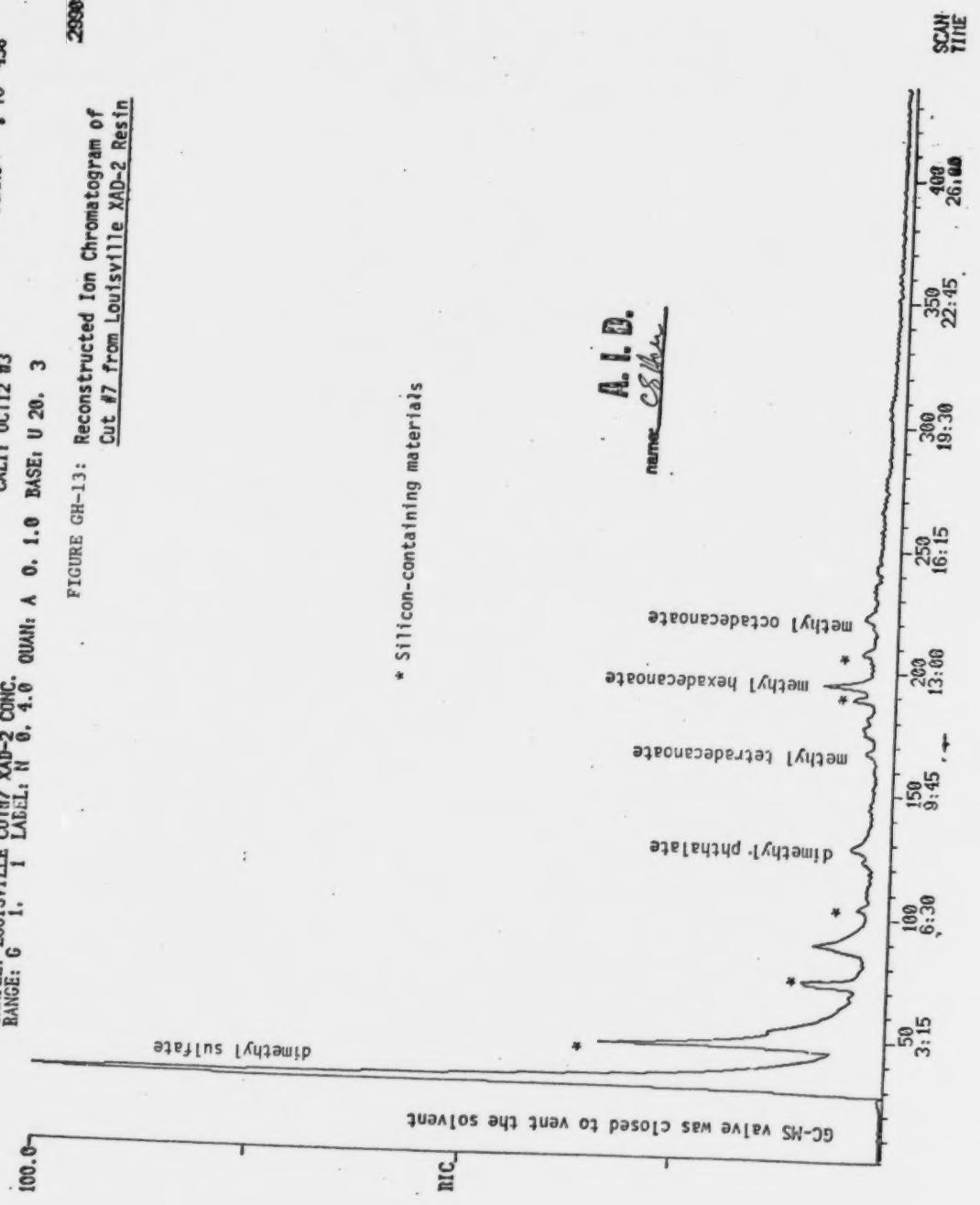
FIGURE GH-12: Reconstructed Ion Chromatogram of
 Cut #6 from Louisville XAD-2 Resin



252<

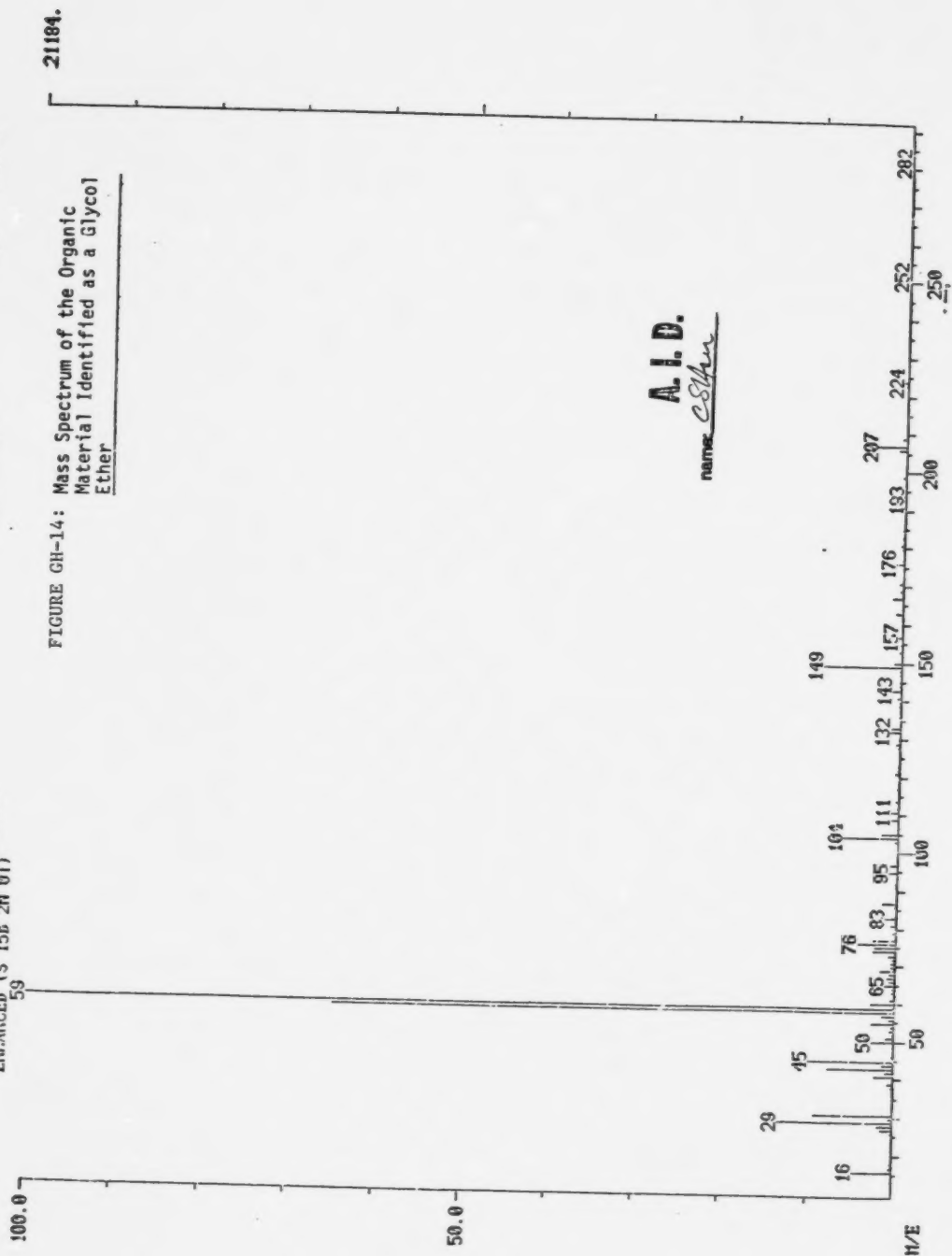
RIC 10/12/81 16:06:00
 SAMPLE: LOUISVILLE CUT#7 XAD-2 CONC.
 RANGE: 6 1. 1 LABEL: N 0. 4.0 QUNN: A 0. 1.0 BASE: U 20. 3
 DATA: 811033 #1
 CALL: OCT12 #3
 SCANS 1 TO 438

FIGURE GH-13: Reconstructed Ion Chromatogram of
 Cut #7 from Louisville XAD-2 Resin
 2990000.



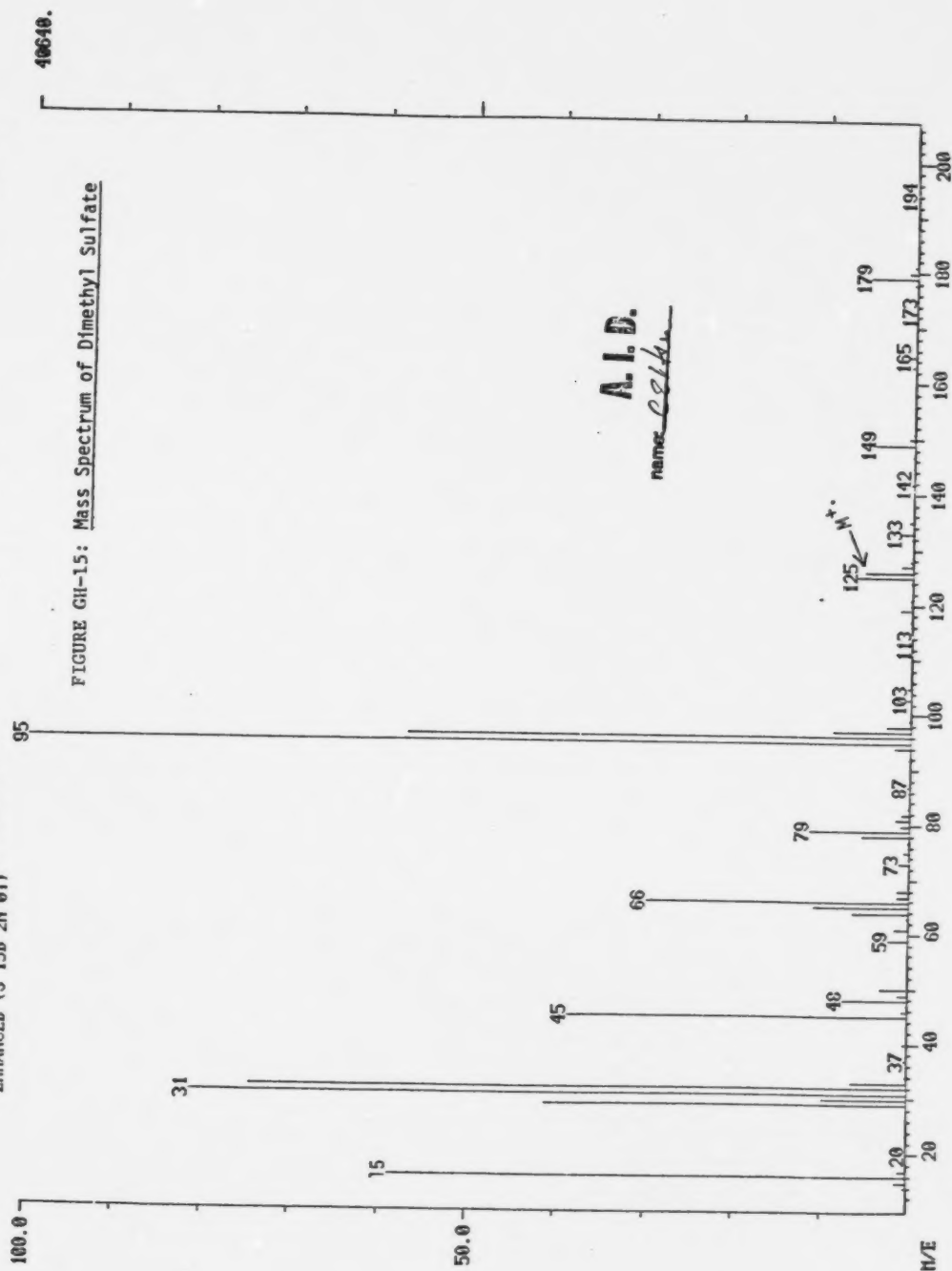
MASS SPECTRUM
10/09/81 10:02:00 + 13:39
SAMPLE: 8866-9-12 CUT06 XAB-2
ENHANCED (S 15E 2H 0T)

DATA: 811030 H210
CALI: OCT9 H2
BASE M/E: 59
RIC: 62272.



MASS SPECTRUM
10/12/81 16:06:00 + 2:05
SAMPLE: LOUISVILLE CUT#7 XAD-2 CONC.
ENHANCED (S 15B 2H 01)

DATA: 811033 H32
CALI: OCT12 H3
BASE H/E: 95
RIC: 244992.



255<

FTIR ANALYSIS OF COAL FRACTIONS

o Louisville LC Cut 1

Cut 1 is principally aliphatic hydrocarbon. Some aromatics (3050, 1600, 875, 812, 770, 745 cm^{-1}) are observed.

o Louisville LC Cut 2

Cut 2 appears to consist of alkyl aromatics. It is intermediate in aromaticity between cuts 2 and 3 of another boiler tested under this program.

o Louisville LC Cut 3

Cut 3 consists of alkyl aromatics, the aromaticity being significantly higher than cut 2.

o Louisville LC Cuts 4 and 5

Louisville cuts 4 and 5 are very similar to the same cuts at another boiler tested under this program.

o Louisville LC Cut 6

Louisville cut 6 is contaminated with 1-methyl-2-pyrrolidinone. The absorptions of the NMP masks many of the sample absorptions making identifications difficult. Cut 6 appears to be a highly aromatic, phenolic type material.

o Louisville LC Cut 7

Cut 7 is a highly aromatic, highly oxygenated (phenolic) material. A 1650 cm^{-1} C=O due to amides or conjugated ketone (quinone) compounds is prominent.

APPENDIX I

EXXON SUMMARY AND ANALYSIS OF
RESEARCH TRIANGLE INSTITUTE (RTI) AND
BATTELLE COLUMBUS LABORATORIES (BCL) BIO-ASSAY REPORTS

The following pages summarize the biological testing reports by Battelle and RTI. This summary was written by Mr. J. S. Leary, a biological toxicologist, and consultant to Exxon.

LEVEL 1 ENVIRONMENTAL ASSESSMENT,
BIOLOGICAL TESTS FOR PILOT STUDIES
CONESVILLE BOILER

Summary

The objective of this Level 1 test was to define the toxicity of effluents and byproducts resulting from the combustion of coal in a power plant boiler. The results of this biological study are intended to complement the chemical and physical data gathered in the Level 1 Environmental Assessment program and to serve as a guide in the planning of subsequent levels of study. The results indicate that the coal, electrostatic precipitator ash (ESP) and sluice water are not mutagenic. The Rat Alveolar Macrophage (RAM) Assays were also negative. The Chinese Hamster Ovary Cell Assay yielded toxic responses with coal leachates and sluice water. ESP ash was not subjected to this assay. Moderate to high toxicity was also recorded for some of the aquatic assays. Sluice water caused no toxicity to any of the aquatic species studied, but was stimulatory to the growth of algae.

Identity of Samples:

TABLE GI-1		
SAMPLE IDENTITIES		
SAMPLE TYPE	LOUISVILLE	
	RTI	BATTELLE
	EXXON CODES	
Electrostatic Precipitator Ash Sample Size	MRD-80-67 2 Kg	MRD-80-65 Ca 60 Kg
Sluice Water Sample Size	MRD-80-68 2 Liters	MRD-80-63 25 Gal
Pulverized Coal Sample Size	MRD-80-66 2 Kg	MRD-80-64 Ca 60 Kg

Sample preparation for assays was as follows:

Electrostatic Precipitator Ash

Study Type

Preparation

Ames Assay

ESP ash added directly to Dimethylsulfoxide at 1000, 250, 50, 5 and 1 micrograms/plate.

Rat Alveolar Macrophage

ESP ash added directly to cell medium at 1000, 500, 100, 50 and 10 micrograms/mL.

Rat Acute Oral Study

ESP ash added directly to distilled water at a rate of 1 g/mL.

Aquatic Studies

- o Fresh Water Algal Assay
- o Static Fish Assay
- o Daphnia Assay

700 grams of ESP ash/gal of distilled water agitated for 48 hours - supernatant decanted and filtered through 0.45 μ m millipore membrane filter.

Sluice Water

Sterilized by millipore filtration.

Study Type

Preparation

Ames Assay

100, 10, 5, 1 and 0.1 microliters/plate.

Chinese Hamster Ovarian Assay

71, 36, 18, 3 and 0.3 microliters/mL of cell medium.

Rat Acute Oral Study

10 mL/Kg of body weight.

Aquatic Studies

Used as supplied.

Pulverized Coal

Study Type

Preparation

Ames Assay

Coal ground and screened through 212 μ m size membrane and added directly to Dimethylsulfoxide at 1000, 250, 50, 5, and 1 microgram/plate.

Rat Alveolar Macrophage

Coal ground and screened through 212 μ m size mesh and added to cell medium at a concentration 1000, 500, 100, 50 and 10 micrograms/mL.

Rat Acute Oral Study

212 m size pulverized coal added to distilled water at a level of 1 μ g/mL - 10 mL/Kg of body weight.

Aquatic Studies

- o Fresh Water Algal Assay
- o Static Fish Assay
- o Daphnia Assay

700 grams of ESP ash/gal of distilled water agitated for 48 hours - supernatant decanted and filtered through 0.45 μ m Millipore membrane filter.

Coal Leachate

Pulverized coal ground in Waring Blender and leached in distilled water at 20°C for 16 hours and sterilized by millipore filtration.

<u>Study Type</u>	<u>Preparation</u>
Ames Assay	Above leachate added at 100, 10, 5, 1 and 0.1 microliters/plate.
Chinese Hamster Ovarian Assay	Above leachate added to cell media at 71, 36, 18, 3 and 0.3 microliters/mL DMSO.
Rat Acute Oral Study	Above leachate administered as is at 10 mL/Kg of body weight.

Methodology

There were some modifications of the Ames Assay, but these changes may not have affected the test performance except that the positive controls appear to be lower in response than might have been expected. Thus marginal responses in the test samples could have gone unnoticed. In the Aquatic studies of the Louisville ESP ash and coal leachates a malfunction of the drum rollers was recorded for the coal leachate. Not enough of the sample remained to do an additional leaching, so a leachate of unknown extraction time was used.

In addition to the prescribed methods of sample preparation, a special extraction and concentration was done to attempt to reach toxic levels for the Louisville coal leachate and the sluice water samples. These samples were subjected to an Ames Assay.

In the basic Level 1 biological testing program, it is recognized that useful information could also have been obtained through the study of sub samples from the Source Assessment Sampling System (SASS). However, in this study the total sample from the SASS was quite small and could be utilized only with regard to the physical and chemical assays.

Results

A brief summary of the toxicity rankings can be found in Table GI-2.

The Ames Assay (Tables GI-3 through GI-8) was essentially negative for all samples tested and except for a cytotoxic response in the Soxhlet extracted pulverized coal assay, no toxicity was recorded. Concentrated coal leachate, assayed at doses from 1 μ L/plate up to the toxic dose of 50 μ L/plate, was not mutagenic for either the frameshift strains (TA 1537, TA 1538 and TA 98) or the base pair strains (TA 1535 and TA 100). In most tests the highest dose of 50 μ L/plate results in a cytotoxic reduction in the number of revertants. Since the coal leachate even when concentrated was not mutagenic, the toxicity ranking is "not detectable". The sluice water was not cytotoxic even at the highest level of concentration and therefore receives the same ranking.

TABLE GI-2
TOXICOLOGY RANKINGS

Louisville Samples

Test	Hopper Ash	Sluice Water	Pulverized Coal
Ames	UD	UD	UD
RAM	UD	NT	UD
CHO	NT	M	M
Rat Oral In Vivo	UD	UD	UD
Fat Head Minnow	M	UD	UD
Daphnia Magna	H	UD	UD
Algae	H	UD	H

H = High Toxicity (Activity)

M = Moderate Toxicity (Activity)

L = Low Toxicity (Activity)

UD = Undetected

NT = Not Tested

See Tables GI-12 through GI-16 in this appendix for suggested ranking of biological activity.

AMES ASSAYS

Table GT-3. Toxicity Results - Boiler 2 Samples (Louisville)

Sample	Amount $\mu\text{g}/\text{plate}$	Survivor Ratio ^a							
		TA 98		TA 1538		TA 100		TA 1535	
		-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9
ESP Ash	1000	1.0	0.8	1.0	0.9	1.1	1.0	1.0	0.9
	250	0.9	1.0	1.1	0.9	1.1	1.2	1.0	1.0
	50	1.0	1.0	1.1	0.9	1.2	1.1	1.0	1.0
	5	0.9	0.8	1.0	-	1.0	1.0	1.0	0.9
Pulverized Coal	1	1.0	0.8	0.9	0.9	1.0	1.0	1.0	0.9
	1000	1.1	0.8	1.0	1.0	0.9	0.9	1.0	1.0
	250	0.9	0.8	1.0	1.0	1.0	0.8	1.0	0.9
	50	1.1	0.9	1.0	-	1.0	0.9	1.0	1.0
Sludge Water	5	0.9	0.9	1.0	1.0	1.1	0.9	1.0	0.9
	1	0.8	1.0	1.0	1.0	1.2	0.9	1.0	1.0
	Amount $\mu\text{l}/\text{plate}$								
	100	1.0	0.8	1.0	0.9	1.0	0.9	1.0	1.0
Coal Leachate	10	1.1	0.8	1.0	0.9	0.9	1.0	1.0	1.0
	5	0.9	0.8	1.0	0.8	1.0	1.1	1.1	1.1
	1	0.9	0.8	1.0	0.9	1.0	1.0	1.1	1.1
	0.1	0.9	1.0	1.2	0.8	0.9	-	1.1	1.2
Coal Leachate	100	1.0	0.7	1.2	1.2	0.9	1.1	1.0	1.0
	10	1.0	0.9	1.1	0.9	0.9	1.0	1.1	1.0
	5	1.1	1.1	1.0	1.1	0.8	0.9	1.1	1.0
	1	1.1	1.0	1.2	1.1	1.0	1.0	1.1	1.1
Coal Leachate	0.1	1.1	1.1	1.2	1.2	1.0	1.0	1.1	1.0

^aColonies in sample plate/colonies in solvent control.

AMES ASSAYS

Table GI-4. Mutagenicity Results - Average Number of Revertants - Boiler 2 (Louisville)

Sample	Amount $\mu\text{g}/\text{plate}$	Average Number of Revertants ^a									
		TA 98		TA 1538		TA 100		TA 1535		TA 1537	
		-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9
ESP Ash	1000	23	34	9	22	135	170	46	21	8	15
	250	5	26	8	17	144	181	43	13	6	11
	50	23	33	13	10	144	183	40	18	5	11
	5	22	33	3	13	132	180	46	19	5	14
Pulverized Coal	1	19	26	6	14	152	174	35	21	5	11
	1000	8	32	15	39	105	173	36	20	15	18
	250	12	25	5	31	114	153	41	19	9	17
	50	19	26	16	24	113	141	50	22	9	19
Sludge Water	5	10	20	16	29	125	132	45	17	19	15
	1	11	15	13	24	126	147	40	20	11	19
	100	18	19	7	20	123	160	54	22	3	10
	10	13	17	7	15	127	164	50	22	3	6
Coal Leachate	5	13	23	5	12	131	157	54	23	3	12
	1	6	27	5	18	135	142	48	23	8	7
	0.1	9	19	2	16	135	142	54	18	5	11
	100	22	29	21	37	135	155	41	22	1	9
Coal Leachate	10	11	26	18	24	112	171	41	24	11	9
	5	7	28	12	22	121	160	49	29	8	10
	1	16	23	16	25	133	150	45	20	12	5
	0.1	15	21	13	23	136	137	46	22	8	5

^aAverage number of revertants from 3 replicate plates per dose.

Note: All 4 samples were not assayed on the same day.

AMES ASSAYS

Table GI-5. Positive Controls - Mutagenic Ratio

Sample	Amount $\mu\text{g}/\text{plate}$	Mutagenic Ratio ^a											
		TA 98		TA 1538		TA 100		TA 1535		TA 1537			
		-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9		
2AN	100	2	28	1	15	1	8	1	3	1			
	10		22		38		9		4				
	1		5		10		3		2				
2NF	100	20		19									
	10	11		32									
	1	3		6									
SA	100												
	10												
	1												
QHCL	250												
	25												
	2.5												
												102	
												0.9	
												0.8	

^aRevertants in test plate/revertants in solvent control.

KEY

2AN: 2-aminoanthracene
 2NF: 2-nitrofluorene
 SA: Sodium azide
 QHCL: Quinacrine hydrochloride

AMES ASSAYS

Table GI-6. Positive Controls - Number of Revertants

Sample	Amount μ g/plate	Average Number of Revertants ^a											
		TA 98		TA 1538		TA 100		TA 1535		TA 1537			
		-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9		
2AN	100	49	1209	25	369	121	1253	73	97	9	222		
	10		940		963		1492		111		277		
DMSO	1		205		263		458		72		26		
	100	28	43	18	25	147	158	65	32	7	9		
2NF	100	546		349									
	10	321		570									
DMSO	1	95		105									
	100	28		18									
SA	100												
	10												
H ₂ O	1					756		1192					
	100					451		841					
QHCL	250					208		416					
	25					141		65					
DMSO	2.5									712			
										6			
										6			
										7			

^a Average revertants per plate from 3 replicate plates per dose.

KEY

- 2AN: 2-aminoanthracene
- 2NF: 2-nitrofluorene
- SA: Sodium azide
- QHCL: Quinacrine hydrochloride
- DMSO: Dimethylsulfoxide

AMES ASSAYS

Table GI-7. Solvent Controls for Samples - Average Number of Revertants

Sample	Amount $\mu\text{g}/\text{plate}$	Average Number of Revertants ^a											
		TA 98		TA 1538		TA 100		TA 1535		TA 1537			
		-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9		
DMSO - ESP Ash	100	23	28	11	24	155	204	65	32	7	9		
DMSO - Pulverized Coal	100	14	20	18	25	143	161	65	32	13	20		
DMSO - Sluice Water	100	11	15	3	10	133	142	65	25	4	9		
DMSO - Coal Leachate	100	11	15	17	17	133	142	65	25	4	9		

^a Average number of revertants from 3 replicate plates per dose.

AMES ASSAYS

Table GI-8. Strain Control - Ranges of Spontaneous Revertants

Sample	Amount μ L/plate	Strain							
		TA 98		TA 1538		TA 100		TA 1535	
		-S9	+S9	-S9	+S9	-S9	+S9	-S9	+S9
DMSO	100	14-28	20-43	1-18	19-25	118-155	146-204	7-65	15-51
H ₂ O	100	11-35	15-52	2-17	10-19	115-175	113-194	33-65	12-37
Bacteria Only	100	8-16		5-12		69-140		2-23	2-15

NOTE: Ranges for background spontaneous revertants are from 4-5 runs.

In the Rat Alveolar Macrophage (RAM) Assay (Tables GI-9 through GI-11) no inhibition of macrophage plating efficiency or viability was observed from exposure to pulverized coal and ESP ash. The "Plating Efficiency" table (Table GI-9) shows that between 40-60 percent of the cells exposed to the test sample attached to the bottom of the well, as also occurred in control cultures. The attached cells from replicate plates were subsequently assayed for viability by scoring the percent of cells excluding trypan blue stain. The "RAM Cell Viability" table demonstrates that neither type of sample affected the percent of viable macrophage cells as compared to controls. There was, on the other hand, a dose response relationship for the cadmium chloride positive control. In support of the above observations the adenosine triphosphate (ATP) content of macrophage cells was measured enzymatically and found to be consistent with the above studies (see Table GI-11).

The Chinese Hamster Ovary (CHO) Cell Cytotoxicity Assay showed only a mildly toxic response for the Louisville coal leachate and sluice water. There was no clear cut dose response relationship for those samples as compared to the cadmium chloride positive control.

The Rat Acute Oral Study indicates that all samples at 10 g/Kg and 10 mL/Kg were nontoxic, in that no animals died at these levels which were the highest doses administered.

Aquatic Study Summary

Louisville Samples

The sluice water sample and the leachate from the coal sample showed no toxic effect on either fathead minnows or Daphnia magna. The electrostatic precipitator (ESP) ash leachate was toxic to both organisms. The sluice water was very stimulatory to Selenastrum capricornutum; however, both leachates inhibited the growth of the algae.

Two minor problems were encountered during the testing of this series of samples. The controls for the fish assay of the ESP Ash Sample (MRD-80-065) showed greater than 10 percent mortality, which invalidates the test. Due to technical error, the algae test for the same sample was ended 24 hours too early. Both tests were repeated with no further problems.

Discussion

Ames assays of ESP fly ash from other coal fired boilers have also been negative with regard to mutagenicity (Reference 2 and 3). However, stack breaching ash in the 3 micron to sub micron size collected at a temperature of about 100°C has been shown to have moderate mutagenic activity (Reference 4). As the sampling temperature is increased the biological activity becomes less. At 350°C most of the activity is absent (Reference 2). This is probably due to the volatility of the toxicants. The published

TABLE GI-9

PLATING EFFICIENCY (PERCENT CELLS ATTACHED) OF EXPOSED RAT
ALVEOLAR MACROPHAGE CELLS IN VITRO

Sample	Concentration ($\mu\text{g/mL}$)	Cell Number		TOTAL (Total Cells)* ($\times 10^{-4}$)	Plating Efficiency (% Cells Attached)
		Media ($\times 10^{-4}$)	Attached ($\times 10^{-4}$)		
Control	-	4.2	2.9	7.1 (9.7)	41
CdCl ₂	0.183	4.5	4.0	9.5 (8.0)	42
CdCl ₂	1.83	4.4	4.3	12.0 (12.0)	62
CdCl ₂	9.15	7.1	5.1	12.0 (15.0)	42
CdCl ₂	18.3	5.7	6.2	12.0 (17.0)	52
CdCl ₂	183.3	5.4	7.7	13.0 (16.0)	59
Pulverized Coal (Louisville)	1000	6.4	3.3	9.7 (9.5)	34
	500	5.6	3.3	8.9 (8.6)	37
	100	6.1	3.4	9.5 (8.9)	36
	50	5.2	4.1	9.3 (11.0)	44
	10	5.8	3.6	9.4 (11.0)	38
ESP Ash (Louisville)	1000	8.1	4.9	13.0 (13.0)	38
	500	8.0	5.9	14.0 (12.0)	42
	100	7.5	4.7	12.0 (11.0)	39
	50	7.3	5.5	13.0 (10.0)	43
	10	7.0	6.2	13.0 (12.0)	47

*The number in parenthesis is the total number of cells from a separate well used as a control for loss of cells during analysis.

Data shows that between 40 and 60 percent of the cells exposed to the test sample attached to the bottom of the culture well. The efficiency is about equal to that of cadmium chloride controls.

TABLE GI-10

RAM CELL VIABILITY

VIABILITY OF EXPOSED RAT ALVEOLAR MACROPHAGE CELLS IN VITRO
EXPRESSED AS A PERCENT OF THE TOTAL NUMBER OF CELLS COUNTED

Boiler No.	Sample Concentration ($\mu\text{g/mL}$)	Plating Efficiency (% Cells Attached)	% Viability (Trypan Blue)
Louisville			
Pulverized Coal	1000	34	98
	500	37	98
	100	36	98
	50	44	98
	10	38	98
ESP Ash	1000	38	98
	500	42	98
	100	39	97
	50	43	97
	10	47	97
Cadmium Chloride Control	0.183	42	98
	1.83	62	96
	9.15	42	67
	18.3	52	49
	183.3	59	48
	Blank	41	98

Neither Pulverized Coal nor ESP Ash decreased uptake of trypan blue as compared to the dose related effect of cadmium chloride.

TABLE GI-11

ATP CONTENT

ADENOSINE TRIPHOSPHATE (ATP) CONTENT OF IN VITRO EXPOSED
RAT ALVEOLAR MACROPHAGE CELLS

Test Sample	Concentration ($\mu\text{g/mL}$)	ng ATP per 10 ⁵ Cells Plated	% ATP of Control
Louisville ESP Ash	1000 500 100 50 10	110 172 170 180 140	82 128 127 134 104
Pulverized Coal	1000 500 100 50 10	114 138 110 156 144	85 103 82 116 107
Positive Control CdCl ₂	183.0 18.3 9.2 1.8 0.18 0	0 0 4 26 108 134	0 0 3 19 81 100
Untreated Cells (Vehicle Only)			

The results of the ATP Assay are consistent with the findings in the two previous tables (Tables GI-9 and GI-10) which show an absence of dose-response cytotoxic effect to RAM Cells for ESP Ash and Pulverized Coal.

literature also suggests that the extraction procedures can be important with regard to the level of mutagenic activity observed (Reference 4). The fly ash samples used in this present study did not have a very high concentration of organic matter, based on the chemical and physical analysis of the SASS samples. Therefore, the efficiency of the extraction procedures is probably a mute point.

What effect this sampling technique may have had on the level of toxicity observed in the other bioassays is not clear but it has been reported that the CHO Assays tend to follow the Ames Assay with regard to positive or negative findings (Reference 5).

Conclusions

1. The samples from Louisville and from another boiler tested under this contract are somewhat similar in their biological activity as demonstrated by the seven assay methods used.
2. The negative Ames Assay response is consistent with studies of similar samples obtained under similar conditions.
3. It is assumed that at the temperatures of approximately 310°F to 325°F (the temperature just prior to the electrostatic precipitators) most of the toxicants collected and measured in this program were in the vapor phase and passed up the stack.
4. An independent study by another research group on another boiler gave very similar results to an Exxon study on the same boiler thus helping to assure the quality of the data reported here.
5. To confirm the presence of mutagenic substances in the fly ash down stream of the ESP, some modifications of the sampling procedures will be necessary in future tests.

References For This Appendix

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The last tables in this appendix are suggested rankings of biological activity.

TABLE GI-12 AMES ASSAY EVALUATION CRITERIA

Mutagenic Activity	Solids (MEC in mg/plate)	Liquids (MEC in μ L/plate)	Organic Extracts (MEC in μ L/plate)
High	<0.5	<2	<2
Moderate	.05-.5	2-20	2-20
Low	.5-5	20-200	20-200
Not detectable	>5	>200	>200

TABLE GI-13 RAM ASSAY EVALUATION CRITERIA

Toxicity	Solids (EC ₅₀ in μ g/ml)	Aqueous Liquids (EC ₅₀ in μ L/ml)	Nonaqueous Liquids (EC ₅₀ in μ L/ml)
High	<10	<6	<.2
Moderate	10 to 100	6 to 60	.2-2
Low	100 to 1000	60 to 600	2-20
Not detectable	>1000	>600	>20

TABLE GI-14 CHO ASSAY EVALUATION CRITERIA			
Toxicity	Solids (EC ₅₀ in g/mL)	Aqueous Liquids (EC ₅₀ in L/mL)	Nonaqueous Liquids ^a (EC ₅₀ in L/mL)
High	<10	<6	<.2
Moderate	10 to 100	6 to 60	0.2-2
Low	100 to 1000	60 to 600	2-20
Not Detectable	>1000	>600	>20
^a Criteria for nonaqueous liquids are tentative and under evaluation.			

TABLE GI-15 ACUTE <u>IN VIVO</u> RODENT ASSAY EVALUATION CRITERIA		
Toxicity	Solids (LD ₅₀ in g/kg)	Liquids (LD ₅₀ in mL/kg)
High	<0.1	<0.1
Moderate	0.1 to 1	0.1 to 1
Low	1 to 10	1 to 10
Not Detectable	>10	>10

TABLE GI-16 DEFINITION OF TOXICITY CATEGORIES FOR AQUATIC ECOLOGICAL ASSAYS

Assay	Activity Measured	Sample Type ^a	MADB	Units	Range of LC50 or EC50 Concentrations		
					High	Moderate	Low
Freshwater Fish	96-hr LC50 ^c (lethality)	S L	1 100	g/L percent	<0.01 <20	0.01-0.1 20-75	0.1-1 75-100
Freshwater Invertebrate	48-hr EC50 ^e (immobilization)	S L	1 100	g/L percent	<0.01 <20	0.01-0.1 20-75	0.1-1 75-100
Freshwater Algae	120-hr EC50 (growth inhibition)	S L	1 80	g/L percent	<0.01 <20	0.01-0.1 20-75	0.1-1 75-100
Marine Fish	96-hr LC50 (lethality)	S L	1 100	g/L percent	<0.01 <20	0.01-0.1 20-75	0.1-1 75-100
Marine Invertebrate	96-hr EC50 (immobilization)	S L	1 100	g/L percent	<0.01 <20	0.01-0.1 20-75	0.1-1 75-100
Marine Algae	120-hr EC50 (growth inhibition)	S L	1 100	g/L percent	<0.01 <20	0.01-0.1 20-75	0.1-1 75-100

^aS = solid, L = aqueous liquid. Nonaqueous liquids are evaluated on an individual basis due to variations in samples such as vehicle, percent organic vehicle, and percent solids.

^bMAD = Maximum applicable dose.

^cLC50 = Calculated concentration expected to kill 50 percent of population.

^dND = Not detectable.

^eEC50 = Calculated concentration expected to produce effect in 50 percent of population.

The MAD for routine freshwater algae testing of liquids is 80 percent rather than 100 percent as in the other tests.

Evaluation of low (L) or not detectable (ND) results for this test should take into account. Samples can be retested at higher concentrations upon the recommendation of the Project Officer.

APPENDIX J

QUALITY ASSURANCE (QA) OF ULTRASONIC THICKNESS (UT) DATA

Various methods were employed to evaluate and correct systematic influences on the ultrasonic thickness data and to insure its high quality.

All tubes measured at this boiler had rifled (ribbed) inner surfaces. And, since it was decided to measure the trough (thin-wall part) of each tube, one of the first QA experiments (4/10/78) evaluated the operators' ability to find the desired portion of the tube for measurement.

The following figure shows a sketch of the section of new tubing used for the experiment as well as a graph of wall thickness vs. distance along the tube. The data was gathered after an index line 30 mm long was marked in 1 mm graduations along the outside of the tube. Then, an ultrasonic thickness gauge was used by several operators to scan the wall thickness along the index line (from the outside of the tube).

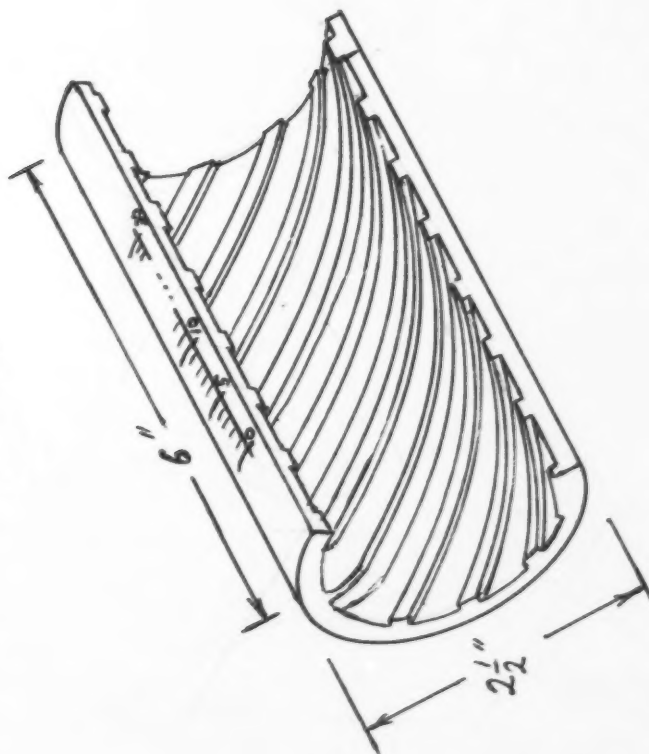
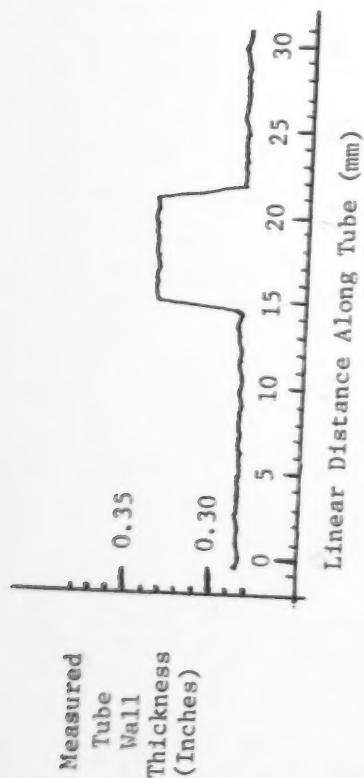
Three different operators made a total of at least eight scans in order to detect the position of the rib from the outside of the tube. All found the position of the rib edge within ± 1.0 mm of the norm.

The ultrasonic method was able to detect the sharp rise and definition of the rib edge as is evidenced by the squareness of the step in the already mentioned graph of thickness vs. distance. Repeatability of the measurements was also very good.

Throughout the program, several other experiments were performed to evaluate data repeatability. One such experiment, conducted during the November, 1979 measurement period, was used to check data repeatability, and also to evaluate a surface cleaning procedure (sandblasting) used in a previous program. In the experiment, nine points on a single new tube were measured and remeasured several times, before and after surface cleaning by sandblasting.

The data on the following table ("REPEATABILITY AND SURFACE PREPARATION CHECK") show that although individual reading may vary widely, the averaging of such readings will "smooth-out" the data. For groups of measurement locations on new tubes, measured under comfortable conditions, the group's average is repeatable within about 1/2 mil (a fraction of a percent). Also, the error introduced by the pre-measurement cleaning procedure could be about one mil. (In this case, the average measured thickness actually increased slightly after sandblasting. This effect has been seen on other occasions, but has not yet been explained.).

Detection of Rifle Rib
Edge by Ultrasonic Scan
From Outside of Tube



REPEATABILITY AND SURFACE PREPARATION CHECK

Data is for new panel No. 5, tube No. 1, hot side, thin part of rifling (mils).

Location	Before Sandblasting		After Sandblasting		Loss = (Before-After)
	1st Time	2nd Time	1st Time	2nd Time	
Top Point	261.3	261.9	262.5	263.1	-1.2
	260.5	261.4	260.3	260.4	+0.6
	263.1	264.0	269.5	269.1	+0.1
	265.4	266.3	267.3	267.5	-0.4
	271.0	272.8	275.2	275.0	+0.2
Bottom Point	270.3	269.5	270.4	270.0	+0.2
	265.4	265.5	266.1	266.5	-0.3
	268.0	268.3	266.6	266.5	-0.8
	263.3	264.2	264.5	264.8	+1.6
					-0.9
Average	265.5	266.0	266.9	267.0	-1.2
Grand Average (Both Times)	265.7		267.0		-1.2

Other QA tests were performed throughout the program to ensure minimal metal removal during the surface preparation step (cleaning by motorized wire brush). For example, the following table shows the results of excessive wire brushing on measured tube wall thickness. The data were gathered during the first (Fall 1979) series of measurements and are the results of measurements taken on a relatively clean (no slag) non-rifled tube in the hopper slope. In the experiment, a single point was measured nearly twenty times after each of several wire brushing steps. The results show that heavy cleaning of the tube surface will cause the thickness reading to be low by only about 1.5 mils or about 1/2%.

Effect of Excessive Surface Cleaning
(by Motorized Wire Wheel Brush)
on Measured Thickness

Tube surface preparation	Measured Tube Wall Thickness (mils)	
	Average Reading	Minimum Reading
Tube with no slag Prior to wire brushing	294.9	294.3
After 5 to 20 seconds of light dusting with motor- ized wire rotary brush wheel	294.5	293.9
Additional severe wire brushing for 30 seconds with heavy sparks flying continuously during the abrasion	293.5	292.5

Another data repeatability experiment was performed in March 1982. In this experiment, a portion of the front wall was measured, but because the data sheet was lost, those points were remeasured. Later, when the original data sheet was found, it served as a set of duplicate measurements for a repeatability check as is summarized on the next table ("DATA REPRODUCIBILITY CHECK").

DATA REPRODUCIBILITY CHECK*

Tube Wall Thickness, Thin Part of Rifling (Mils)

(Data is for Front Wall, LG&E, Mill Creek No. 3, March, 1982)

Measurement Location	1st Time	2nd Time	2nd-1st
B 122 T	261.7	261.7	+0.0
B 122 M	261.4	267.0	+5.6
B 122 B	263.8	260.5	-3.3
B 134	268.3	266.7	-1.6
B 140 T	258.0	253.0	-5.0
B 140 B	258.2	259.5	+1.3
B 146	262.5	262.6	+0.1
B 152 T	268.3	266.8	-1.5
B 152 M	268.4	266.6	-1.8
B 152 B	268.5	266.7	-1.8
B 164	272.3	271.5	-0.8
B 170 T	276.5	273.0	-3.5
B 170 B	275.6	272.0	-3.6
B 182	266.5	267.0	+0.5
B 194 T	266.4	268.2	+1.8
B 194 M	266.5	265.0	-1.5
B 194 B	265.7	266.5	+0.8
C 130 T	260.6	260.0	-0.6
C 130 B	259.2	262.5	+3.3
C 142	253.9	262.0	+9.1
C 154 T	275.9	277.0	+1.1
C 154 M	272.6	271.0	-1.6
C 154 B	271.8	270.2	-1.6
C 160	266.5	260.5	-6.0
C 172 T	263.1	265.0	+1.9
C 172 B	263.0	262.1	-0.9
C 178	260.8	262.0	+1.2
C 184 T	271.7	271.0	-0.7
C 184 M	270.5	270.5	+0.0
C 184 B	268.4	267.8	-0.6
C 190	265.3	265.0	-0.3
Average			-0.32

*The data is from duplicate measurements taken about 1 day apart because the original data was thought to be lost. It was later found.

It should be noted that for the 31 data points, the average difference between the initial and repeat measurements was only 0.32 mils, and only about 10% of the points had differences of more than four mils. Also it should be noted that based on these repeatability experiments, all measurements, on the average, were repeatable to within a fraction of a percent of the true thickness.

Before the ultrasonic gauge could be used, the surface of each tube had to be cleaned to expose the bare metal. Some researchers, however, feel that such removal of the tubes' outer deposits will bias future corrosion at that spot. So, in order to assure data quality, an experiment was performed to evaluate and eliminate any such bias (if it exists.)

On many tubes, bias was eliminated by not measuring the point of interest at all. Instead, a point a few inches above the point of interest, and another point a few inches below the point of interest were measured. The thickness of the point of interest was assumed to be equal to the average of the "above" and "below" measurements. But since the point of interest was not touched, its future corrosion rate would not be influenced by the cleaning and measurement procedure around it.

To help test the assumption just mentioned, some tubes on all four walls were measured (during the second UT measurement visit) at all three places — that is, at the point of interest, as well as at points a few inches above and below that central point. The results for those measurements performed on the back wall are shown below:

TUBE WALL THICKNESS RESULTS (Mill Creek No. 3, Rear Wall)

Difference between average of top and bottom thickness measurements, and thickness at midpoint: $\left(\frac{T + B}{2}\right) - M$ (mils)

Top x

Mid x

Bot x

AVERAGE FOR	LEVEL A	LEVEL B	LEVEL C	LEVEL D	LEVEL E	LEVEL F	ALL ELEVATIONS
AVERAGE DIFFERENCE (mils): $\left(\frac{T + B}{2}\right) - (M)$	-8.75	-19.83	- 8.7	-18.2	+11.1	+13.0	-6.9

The table shows that on the average, during the second measurement visit, for the points reported, the central points were 0.007 inch thicker than the averages of two points a few inches away. But as the reader can see, the scatter of the data is quite large. Therefore, the results were not heavily considered in data evaluation for this report. Instead, for measurement locations where several readings were made within a small local area on a single tube, the average of all such measurements was considered as the tube's true wall thickness at the point of interest.

Another type of error could be introduced if tube wall thickness was measured at some location other than the desired location. Each wall in this boiler is about 250 tubes or about 50 feet wide and about 200 feet tall. In order to measure corrosion rates, the researchers measured the thickness of individual points on the boiler wall, and then, two years later tried to find the same points for remeasurement. Admittedly, the repeat measurement on my points may have been performed at a point a few inches away from the desired point at which the original measurement was made. An experiment was performed to evaluate any error that might be introduced by such a change in measurement location.

The experiment was designed to evaluate errors that might occur as a result of making a measurement at the wrong location, but near the correct location. In the worst case, this might occur if the operator miscounted the tubes and thus measured the wrong tubes during one of the work visits. In the experiment, five groups of points were measured. Then the same points were measured, but on adjacent tubes. This had the same effect of miscounting, and thus measuring the wrong tubes. The results are shown below. (The experiment was performed on the left wall.)

Analysis of Errors Introduced by Measuring the Wrong Tubes				
	Average for Right Tubes* (mils)	Average for Wrong Tubes* (mils)	Average R-W (mils)	Average Absolute Error (mils)
Level A Tubes 1-65	284.59	287.13	-2.54	+2.54
Level A Tubes 66-120	284.48	291.76	-7.28	+7.28
Level C Tubes 1-72	267.11	269.68	-2.56	+2.56
Level C Tubes 73-120	271.57	263.18	+8.39	+8.39
Level D Tubes 80-98	261.27	258.36	+2.91	+2.91
Average			-0.22	+4.74

*Each of these averages represents about 10 points.

The table shows that for small groups of (about 10) points, the group's average does not depend heavily on the locations of the measurements as long as each actual location is near each desired location. For this example, the average error for the five groups caused by measuring the wrong tubes was less than 5 mils.

In addition to the few examples presented in this appendix, QA data was gathered on several other occasions to assure uniformity between operators, and also to assure accuracy of calibration.